Chapter 4
General Risk Levels
Crude Oil Pipelines Under Study

Before reviewing the specific study results, it is helpful to review a profile of the crude oil pipelines included in this study. To reiterate the information presented earlier in Chapter 1, the following pipelines have been included in this study and database:

- pipelines for the transportation of crude oil that operate at gravity or at a stress level of 20% or less of the specified minimum yield strength of the pipe; and,

- pipelines for the transportation of petroleum (crude oil) in onshore gathering lines located in rural areas.

Pipelines meeting this criteria have been included in the study and database, whether they were operating or not during the study period; even abandoned, idle, or otherwise out of service pipelines have been included in the study and database. The following pipelines were *excluded* from the data base and study:

- interstate and intrastate pipelines which are currently regulated by the CSFM or USDOT;

- gathering lines located entirely within the boundary of DOGGR oil field boundary, or which cross a boundary where two DOGGR oil fields are contiguous and are contained entirely within multiple DOGGR oil fields;

- flow lines located entirely within the boundary of a DOGGR designated oil field boundary, or which cross a boundary where two DOGGR oil fields are contiguous and are contained entirely within multiple DOGGR oil fields;

- natural gas pipelines;

- refined petroleum product pipelines; and

- abandoned pipelines which have been physically removed.

It=s also important to understand the leak incidents which have been included this study. As noted earlier, the criteria for defining these leaks was established by the Steering Committee. The criteria for reporting leaks to the California Office of Emergency Services (OES) (one barrel or more, or any spill onto water, or any spill which could threaten ground water) was selected for use. Unfortunately, the OES spill database could not be used for this study, since it does not contain sufficient pipeline and leak details to facilitate any specific analysis.

The study period was established as a three year period from January 1993 through December 1995.

Although over 1,200 questionnaires were initially distributed to potential study participants, the actual number of leaks and the length of crude oil pipelines included in this study is relatively small; there are simply very few miles of pipeline which met the study criteria. This data set only included ten (10) leaks of one barrel or greater, which occurred during the three year study period, from only 496 miles of pipelines. This data sample is simply too small to draw many meaningful conclusions. Despite the instructions requesting that only leaks of one barrel or greater be reported (except for those meeting other criteria) we received ten leak reports for spills of less than one barrel. Since this data was not uniformly available or reported for all of the operators, these incidents of less than one barrel were not included in the study. It=s worth noting that the total damage from these leaks, which were excluded from the study, was nominal, averaging $3,460 per incident.

For comparison purposes, we have also presented data for CSFM-regulated hazardous liquid pipelines, as reported in the 1993 California Hazardous Liquid Pipeline Risk Assessment. Throughout this section, comparisons have been made between California=s crude oil pipelines under study and the CSFM-regulated pipelines, for reference. Profiles of these pipeline data sets are summarized below:

Description	Crude Oil Pipelines Under Study	CSFM Regulated Pipelines
Total Miles of Pipelines	496	7,800
Data Period	1993-1995 (3 yrs)	1981-1990 (10 yrs)
Total Miles of Piggable Pipeline/(% of total)	28 (5.6%)	4,495 (57.6%)
Total Number of Pipelines or Line Sections	113	552
Average Length of Each Pipeline (miles)	4.39	14.1
Mean Year of Original Construction	1953	1957
Mean Diameter of Pipe (inches OD)	7.5	12.3
Mean Diameter of Piggable Pipe (inches OD)	15.1	14.3
Largest Cause of Incidents / (% of all leak incidents)	Ext Corrosion (60%)	Ext Corrosion (59%)
Miles of Bare or Uncoated Pipe / (% of Total)	1.3-Bare/149-Unknown (0.3% bare; 30% unknown)	530 (6.8%)

Description	Crude Oil Pipelines Under Study	CSFM Regulated Pipelines
Miles of Cathodically Protected Pipe / (% of Total)	317 (64%)	6,976 (99.4%)
Mean Normal Operating Temperature	74.2°F	97.9°F
Number of Leaks During Study Period	10	514
Average Spill Size (bbl)	122.1	408
Median Spill Size (bbl)	3	5
Average Damage Per Incident (Uninflated - $US 1994)	$39,000	$211,000
Median Damage Per Incident ($US 1994)	$5,000	$10,710
Average Age Of Leak Pipe (years)	39.9	40.8
Average Diameter of Leak Pipe (inches)	7.5	10.2
Mean Normal Operating Temperature of Leak Pipe	64.5 °F	109.7°F
Injuries During Study Period	0	49
Fatalities During Study Period	0	3

In the table above, the terms *mean* and *average* were used to differentiate between the methods used to calculate the values. *Average* values were determined by simple division. For example, the average spill size was determined by dividing the sum of each individual spill volume by the total number of spills. *Mean* values, on the other hand, were determined by *weighting* the individual parameters by pipe length and the number of years of service during the study period. For instance, the mean normal operating temperature was determined as follows:

$$T_{mean} = \Sigma \ \{T_i L_i Y_i + T_{(I+1)} L_{(I+1)} Y_{(I+1)} + \ldots\} \div \Sigma \ \{L_i Y_i + L_{(I+1)} Y_{(I+1)} + \ldots\}$$

where: T_{mean} = mean normal operating temperature
T_i = normal operating temperature for line segment
L_i = length of line segment
Y_i = number of years of line segment operation during study period

We believe that this weighting method provides a much more meaningful representation of mean values for many parameters than simple division. It has been used where appropriate to determine the values shown in many of the tables presented in this report.

4.1 Overall Incident Causes

The overall incident rate for all pipelines included in this study was 6.72 incidents (one barrel or greater) per 1,000 mile years. Table 4-1A presents the detailed data.

As indicated, the leading cause of leak incidents of California=s crude oil pipelines under study from January 1993 through December 1995 was external corrosion, which caused 60 percent of all leaks. The second leading factor was internal corrosion, which caused 20% of all leaks.

The volumes spilled as a result of external corrosion were nominal in size, relative to the spill size resulting from other causes (three barrel average for external corrosion versus 300 barrel average for other causes).

The remaining 20% of the leaks were caused by third-party damage, distributed equally (10% each) between (a) third-party damage due to construction and (b) third-party damage due to farm equipment.

The incident cause distribution for California=s crude oil pipelines under study and CSFM-regulated hazardous liquid pipelines are compared numerically below.

Cause of Incident	Crude Oil Pipelines Under Study	CSFM Regulated Pipelines
External Corrosion	60%	59%
Internal Corrosion	20%	3%
Third Party	20%	20%
Equipment Malfunction	0%	5%
Weld Failure	0%	4%
Operating Error	0%	2%
Other	0%	10%

As shown, external corrosion caused the majority of the leak incidents in both data sets. (The issues regarding this cause of leaks will be explored in more detail in many of the following subsections of this report.)

Table 4-1
Overall Incident Causes - Crude Oil Pipelines Under Study
(Incidents per 1,000 mile years)

Cause of Incident	Number of Incidents	Incident Rate	Percentage
External Corrosion	6	4.03	60%
Internal Corrosion	2	1.34	20%
3rd Party/Construction	1	.67	10%
3rd Party/Farm Equipment	1	.67	10%
Total	106.72	6.72	100%
Number of Mile Years	1,487		
Mean Year of Pipe Construction	1953		
Mean Operating Temperature (1F)	74.2		
Mean Diameter (inches)	7.5		
Average Spill Size (barrels)	122.1		
Average Damage ($US 1994)	$39,020		

Internal corrosion caused a much larger percentage of the pipeline incidents under study (20% versus only 3% for the CSFM-regulated pipeline incidents.) This is not surprising, since many of these pipelines are crude oil gathering lines. As a result, one would expect that they carry a higher percentage of water and other impurities which would tend to increase the internal corrosion rate. In fact, many of these lines (330 miles, 67%) transport crude oil with water cuts between 1% and 3%; 19 miles (4%) transport crude oil with water cuts greater than 3%. This is in contrast to nearly all of the CSFM-regulated trunk lines, which typically transport crude oil with less than 1% water. The remaining 29% of the pipelines under study did not report this parameter.

Third party damage caused 20% of the pipeline incidents in this study. This is the same distribution as the CSFM-regulated hazardous liquid pipelines.

4.2 Incident Rates By Study Year

<u>CSFM-Regulated Pipelines</u>
For the CSFM-regulated hazardous liquid pipelines, varying leak incident rates were observed during the ten year study period. Table 4-2A shows the incident rate break-down for each year during the ten year survey period by cause.

The results demonstrate a slight decline over the ten year period: during the first five years the average incident rate was 8.5; during the latter half the average incident rate was 6.9 leaks per 1,000 mile years. An ordinary least squares line of best fit was determined to evaluate the statistical relevance of this overall leak data by year. It showed that the overall incident rate decreased 0.52 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* for this regression was 0.39. *7 squared* values range from zero to one. They can be interpreted as the proportion of the variation in a given sample which can be explained by the resulting linear equation; they are a comparison of the estimated systematic model with the mean of the observed values. Very simply put, the closer the *R squared* value is to unity, the higher the relevance in the results.)

A similar regression was performed for external corrosion leaks only during the ten year study period. It indicated that the incident rate for external corrosion leaks was decreasing at the rate of 0.21 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* was 0.24.

The decreasing trend in incident rates is especially noteworthy considering the fact that all leak data was gathered at the end of the study period. With the increasing trend towards total leak reporting and recording, one would assume that the more recent data collected from a pipeline operator may be more complete than data regarding leaks which occurred several years ago. This would tend to result in relatively lower incident rates for early study years and a corresponding increasing incident rate trend. However, as discussed earlier, the data indicated a rather significant *decreasing* incident rate trend. This indicates two things: first, it indicates that the data gathered is relatively complete during the earlier years of the study; secondly, it indicates that if any incomplete record keeping did occur during the early years of the study period, the actual decreasing incident rate trend was higher than indicated by the regressions. To reiterate, the data indicated a rather significant decreasing incident rate trend, which may actually have been somewhat understated.

A third regression was performed for leaks caused by all causes except external corrosion during the ten year study period. It indicated that the incident rate for these leaks was decreasing at the rate of 0.19 incidents per year per 1,000 mile years of pipeline operation during the study period. The resulting *R squared* was 0.26. The average spill volumes varied widely during the ten year study period. An ordinary least squares line of best fit was determined to analyze any trend in this data. It indicated a 33.6 barrel per year reduction in average spill size, with an *R squared* of only 0.16.

Finally, ordinary least squares lines of best fit were determined for the average cost of damage per incident during the ten year study period. Prior to running the regressions, all cost data was normalized to constant 1983 US dollars. Using all incidents during the study period yielded a \$33,040 (\$US 1983), \$49,145 (\$US 1994) per year increase in average spill cost, with an *R squared* of 0.27. After deleting the 1989 San Bernardino train derailment, the regression indicated a \$23,366 (\$US 1983), \$34,755 (\$US 1994) per year increase in average spill cost, with an *R squared* of 0.33.

Table 4-2A
Incident Rates by Year of Study - CSFM Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	1981	1982	1983	1984	1985	1986	1987	1988	1989	1990
External Corrosion	4.78	7.21	4.19	3.36	3.14	3.73	5.67	3.95	2.89	3.55
Internal Corrosion	.00	.45	.30	.15	.14	.40	.53	.00	.00	.00
3rd Party/Construction	1.08	2.40	.60	.15	1.43	.67	.66	.79	.79	.53
3rd Party/Farm Equipment	1.08	.15	.90	.00	.00	.13	.13	.13	.13	.00
3rd Party/Train Derailment	.00	.00	.00	.00	.00	.00	.00	.13	.13	.00
3rd Party/Ext Corrosion	.00	.00	.00	.00	.14	.00	.13	.00	.00	.66
3rd Party/Other	.15	.30	.60	.00	.14	.40	.00	.13	.13	.13
Operating Error	.31	.30	.15	.00	.00	.00	.13	.00	.26	.00
Design Flaw	.00	.00	.00	.00	.00	.00	.00	.13	.00	.13
Equipment Malfunction	.15	.60	.45	.15	.43	.00	.40	.92	.26	.39
Maintenance	.00	.00	.00	.00	.29	.00	.00	.00	.39	.00
Weld Failure	.15	.60	.60	.29	.43	.13	.13	.26	.00	.13
Other	.46	.45	.15	.29	.29	.67	.13	.39	.53	.13
Total Number of Incidents	8.18	12.47	7.94	4.39	6.42	6.13	7.91	6.84	5.52	5.65
Number of Mile Years	6,482	6,658	6,675	6,835	7,005	7,501	7,587	7,600	7,609	7,610
Mean Year of Construction	1952	1953	1953	1954	1954	1956	1957	1957	1957	1957
Mean Operating Temp (1F)	97.0	97.4	97.4	96.8	98.4	97.9	98.0	97.9	98.0	98.0
Mean Diameter (inches)	10.8	10.9	10.9	10.9	11.1	12.3	12.3	12.4	12.4	12.4
Average Spill Size (bbl)	285.0	514.7	889.3	83.6	562.9	609.4	266.6	136.2	377.5	127.4
Avg Damage ($1,000 US 1994)	16.4	39.4	138.0	38.1	140.4	255.7	31.8	90.3	968.6	210.3

California Crude Oil Pipelines Under Study

Table 4-2B presents leak incident data for California=s crude oil pipelines under study, by year, during the three year study period. The data sample indicates a sharp increase in the frequency of incidents per year. However, nearly all of the 1995 leaks occurred on one line, which the operator plans to replace. This situation points out the severe limitations of the very small three year data sample; this sample precludes the meaningful analysis of any trends which might exist.

We recommend that an analysis, similar to that conducted for the CSFM-regulated hazardous liquid pipelines, be conducted after several years of additional data has been collected.

Table 4-2B
Incident Rates by Year of Study - Crude Oil Pipelines Under Study
Incidents Per 1,000 Mile Years

Cause of Incident	1993	1994	1995
External Corrosion	.00	6.05	6.05
Internal Corrosion	2.02	.00	2.02
3rd Party/Construction	.00	2.02	.00
3rd Party/Farm Equipment	.00	.00	2.02
Total Number of Incidents	2.02	8.06	10.08
Number of Mile Years	494	496	496
Average Spill Size (bbl)	1.0	295.5	7.6
Average Damage ($US 1994)	$5,000	$92,750	$2,840

4.3 Decade of Construction Effects

CSFM-Regulated Hazardous Liquid Pipelines

The 1993 study regarding CSFM-regulated pipelines concluded that pipe age had a definite effect on the leak incident rates. Table 4-3A shows the variation in leak incident rates by decade of pipe construction for these regulated pipelines. As indicated, pipe construction before 1940 (1926 mean year of construction) had a leak incident rate nearly twenty times that of pipe constructed in the 1980's. An ordinary least squares line of best fit was determined to evaluate the statistical relevance of the overall leak data by year of pipe construction. It indicated that the overall leak incident rate decreased 0.286 incidents per year per 1,000 mile years. The resulting *R squared* for this regression was 0.82. A second regression was performed which excluded all pipe installed prior to 1940. This regression indicated an overall leak incident rate reduction of 0.147 incidents per year per 1,000 mile years, with an *R squared* of 0.86. The study indicated that the vast majority of the difference in leak incident rates occurred because of variations in external corrosion rates. Some of the reasons for this variation may have included:

- The extent of external corrosion is generally considered a function of time. In general, the more time a given portion of pipe is allowed to corrode, the more likely it will be to develop a leak.

- Most believe that modern coatings are generally more effective than older coatings, especially those installed before the 1940's. The older pipe is likely to experience a higher external corrosion incident rate as a result.

- External corrosion rates are generally higher at elevated temperatures.

- Prior to the 1950's, it was common to install pipelines with little or no cathodic protection. For the most part, these older systems have either had new systems installed, or their older systems upgraded, to be consistent with present day practices. However, they often operated for several years with inadequate or no cathodic protection. The corrosion which occurred during these early years likely increased the resulting external corrosion leak incident rate.

An ordinary least squares line of best fit was determined for the external corrosion data only. Using all data, it indicated that the external corrosion rate declined by 0.217 incidents per year per 1,000 mile years, with an *R squared* of 0.79. A similar regression was performed excluding all pipe constructed prior to 1940. This regression indicated an external corrosion rate reduction of 0.097 incidents per year per 1,000 mile years, with an *R squared* of 0.95. However, it should be noted that both of these regressions resulted in a least squares line fit which would indicate a negative incident rate during the study period, which is impossible. However, the point should be made that there is a strong statistical relationship between pipe age and rate of external corrosion; the newer the pipe, the lower the external corrosion incident rate.

A third ordinary least squares line of best fit was prepared for leaks caused by all causes except external corrosion. It indicated that the incident rate for these leaks decreased at the rate of 0.069 incidents per year per 1,000 mile years. The resulting *R squared* was 0.80.

Table 4-3A
Incident Rate by Decade of Construction - CSFM Regulated Pipelines
Incidents Per 1,000 Mile Years

Cause of Incident	Pre 1940	1940-49	1950-59	1960-69	1970-79	1980-89
External Corrosion	14.12	4.24	2.47	1.47	1.24	.00
Internal Corrosion	.38	.27	.10	.16	.00	.28
3rd Party/Construction	1.96	1.06	.68	.66	.25	.28
3rd Party/Farm Equipment	.53	1.33	.05	.00	.00	.00
3rd Party/Train Derailment	.00	.00	.00	.05	.25	.00
3rd Party/Ext Corrosion	.45	.00	.10	.33	.00	.00
3rd Party/Other	.30	.13	.05	.05	.00	.00
Operating Error	.30	.13	.00	.11	.25	.00
Design Flaw	.08	.00	.00	.00	.00	.14
Equipment Malfunction	.38	.53	.10	.60	1.24	.00
Maintenance	.00	.00	.24	.00	.00	.00
Weld Failure	.38	.27	.15	.44	.25	.00
Other	.83	.13	.24	.27	.25	.28
Total Number of Incidents	19.70	8.08	4.17	4.15	3.72	.97
Number of Mile Years	13,247	7,546	20,612	18,311	4,030	7,252
Avg Year of Construction	1926	1944	1944	1965	1974	1985
Average Operating Temp (1F)	125.2	79.7	89.4	91.4	99.8	104.1
Average Diameter (inches)	8.58	11.11	11.82	11.27	13.79	19.55
Average Spill Size (bbl)	162	492	246	1,306	53	789
Average Damage ($US 1994)	46,517	177,902	252,479	738,001	127,589	244,407

California Crude Oil Pipelines Under Study

While the CSFM-regulated hazardous liquid pipeline data indicated a very strong correlation between pipe age and leak incident rates, we did not find the same correlation for the crude oil pipelines included in this study. Table 4-3B presents the leak incident rates by decade of pipeline construction. As shown, there is little correlation between pipe age and the incident rates for these pipelines.

The oldest group of pipe, which was that constructed before 1940, had a leak incident rate of 2.21 incidents per 1,000 mile years. The group with the highest leak incident rate was constructed in the 1960's; this group had a leak incident rate of 16.95 incidents per 1,000 mile years.

Similar to the analysis for the CSFM-regulated hazardous liquid pipelines, an ordinary least squares line of best fit was used to evaluate the statistical relevance of the overall leak data, by year of pipe construction, for the crude oil pipelines under study. It indicated that the overall leak incident rate was decreasing at the rate of 0.030 incidents per 1,000 mile years, for each year of decreasing pipe age. However, the resulting *R squared* for this regression was only 0.01, indicating little, if any, statistical relevance to this data. A similar regression was performed for external corrosion leaks only. This analysis indicated that the external corrosion leak incident rate was decreasing at the rate of 0.10 incidents per 1,000 mile years for each year of decreasing pipe age; the *R squared* for this regression was 0.14. As a result, the data for the crude oil pipelines under study does not indicate a statistical correlation between pipe age and the resulting leak incident rate. We suspect that this is largely due to the limited data sample available for this study. With a larger data sample, we would anticipate results similar to those for the CSFM-regulated pipelines for the same reasons discussed at the beginning of this section.

Table 4-3B

Incident Rate by Decade of Construction - Crude Oil Pipelines Under Study

Incidents Per 1,000 Mile Years

Cause of Incident	**Pre 1940**	**1940-49**	**1950-59**	**1960-69**	**1970-79**	**1980-89**	**1990-95**
External Corrosion	2.21	13.09	.00	11.30	.00	.00	.00
Internal Corrosion	.00	.00	4.97	5.65	.00	.00	.00
3rd Party/Construction	.00	.00	.00	.00	.00	5.38	.00
3rd Party/Farm Equipment	.00	.00	.00	.00	.00	.00	.00
Total Number of Incidents	2,21	13.09	4.97	16.95	.00	5.38	.00
Number of Mile Years	451.9	229.1	201.0	177.0	94.4	185.9	21.1
Mean Year of Construction	1930	1945	1954	1967	1974	1985	1992
Mean Operating Temp (1F)	54.3	76.5	70.4	78.2	92.2	102.2	137.1
Mean Diameter (inches)	7.8	6.6	6.1	10.6	6.5	7.4	9.6
Average Spill Size (bbl)	4.0	3.3	25.0	1.7	0.0	589.0	0.0
Average Damage ($US 1994)	$5,000	$6,067	$5,000	$3,333	$0	$176,000	$0

4.4 Operating Temperature Effects

CSFM-Regulated Hazardous Liquid Pipelines

The 1993 CSFM-regulated hazardous liquid pipeline study concluded that pipeline operating temperature had a definite effect on the leak incident rates. Table 4-4A shows the variation in leak incident rates by operating temperature for these CSFM-regulated pipelines.

With the exception of the relatively new pipelines operating at above 180°F (most were built around 1979), higher operating temperatures were directly related to higher leak incident rates. However, the data also indicated that the pipelines operated between 130 and 159°F were also the oldest. As a result, a logistic regression was performed to determine whether or not pipe age was masking the pipe operating temperature effects. The logistic regression results indicated that while holding various factors constant, including pipe age, operating temperature was positively related to the probability of a leak occurring from external corrosion. Operating temperature was not statistically related, however, to the probability of leaks occurring from other causes.

Ordinary least squares lines of best fit were also calculated to evaluate the statistical relevance of this CSFM-regulated pipeline data. For all leaks, the line indicated an increase of 0.11 incidents per 1,000 mile years, per °F increase in operating temperature, with an *R squared* of 0.89. For external corrosion leaks only, the regression resulted in an increase of 0.10 incidents per 1,000 mile years, per °F increase in operating temperature, with an *R squared* of 0.91. For all leaks, excluding external corrosion leaks, the regression resulted in an increase of 0.0077 incidents per 1,000 mile years, per °F, with an *R squared* of only 0.28. These data reaffirm the logistical regression results that the probability of leaks occurring from external corrosion was affected by operating temperature, while leaks from other causes were not affected by operating temperature.

The CSFM-regulated hazardous liquid pipeline data also indicated that spill sizes and monetary damage did not appear to be affected by operating temperature.

Table 4-4A
Incident Rate by Normal Operating Temperature - CSFM Regulated Pipelines
Incidents Per 1,000 Mile Years

Cause of Incident	0-691F	70-991F	100-1291F	130-1591F	1601F+
External Corrosion	.48	1.33	7.11	11.36	11.31
Internal Corrosion	.00	.21	.32	.57	.08
3rd Party/Construction	1.91	.94	.95	.57	.60
3rd Party/Farm Equipment	.00	.30	.47	.00	.08
3rd Party/Train Derailment	.00	.04	.00	.00	.00
3rd Party/Ext Corrosion	.00	.06	.16	.00	.15
3rd Party/Other	.00	.24	.16	.00	.15
Operating Error	.00	.11	.00	.00	.23
Design Flaw	.00	.04	.00	.00	.00
Equipment Malfunction	.00	.24	.16	.57	.98
Maintenance	.00	.09	.16	.00	.00
Weld Failure	.00	.19	.32	.00	.60
Other	.00	.21	1.11	1.14	.45
Total Number of Incidents	2.38	4.01	10.90	14.20	14.63
Number of Mile Years	2,097	46,641	6,332	1,760	13,260
Mean Year of Construction	1960	1959	1953	1947	1951
Mean Operating Temp (1F)	61.66	74.72	103.37	144.84	177.63
Mean Diameter (inches)	8.62	12.58	11.88	9.92	12.96
Average Spill Size (bbl)	12	480	72	7	601
Average Damage ($US 1994)	72,002	363,891	53,866	15,566	142,590

California Crude Oil Pipelines Under Study

The data for California=s crude oil pipelines in this study did not indicate a similar operating temperature versus leak incident rate relationship. As shown in Table 4-4B, there was no correlation between operating temperature and the leak incident rate associated with California=s crude oil pipelines.

An ordinary least squares line of best fit was used to evaluate the statistical relevance of the overall leak data, by operating temperature, for the crude oil pipelines under study. It indicated that the overall leak incident rate was increasing at the rate of 0.06 incidents per 1,000 mile years per 1°F increase in operating temperature. However, the resulting *R squared* for this regression was only 0.08, indicating little statistical relevance to this data.

A similar linear regression was also performed on the external corrosion caused incidents only. This analysis resulted in a *decreasing* external corrosion incident rate of 0.04 incidents per 1,000 mile years, per 1°F increase in operating temperature. The *R squared* for this regression was 0.48, again indicating little statistical relevance to this data. It=s also worth noting that all six of the external corrosion caused incidents occurred on pipelines operating in the ambient temperature category. This group was the largest, comprising 70% of the pipe sample. It was also the oldest pipe, with a 1948 mean year of pipe construction. (See also Section 4.3 of this report for a discussion of pipe age effects.)

For the crude oil pipelines under study, these results do not indicate a statistical correlation between elevated pipe operating temperature and any increased risk of leak incidents. However, one must keep in mind the limited size of this data set. The small number of leaks (10) included in this limited three year study period, with only 496 miles of pipelines, is a very small sample. As noted earlier, this sample may not be large enough to show trends.

Table 4-4B

Incident Rate by Normal Operating Temperature - Crude Oil Pipelines Under Study

Incidents Per 1,000 Mile Years

Cause of Incident	**0-691F**	**70-991F**	**100-1291F**	**130-1591F**	**1601F+**
External Corrosion	6.86	.00	.00	.00	.00
Internal Corrosion	2.29	.00	.00	.00	.00
3rd Party/Construction	.00	.00	21.28	.00	.00
3rd Party/Farm Equipment	1.14	.00	.00	.00	.00
Total Number of Incidents	10.30	.00	21.28	.00	.00
Number of Mile Years	874.0	166.0	47.0	34.0	124.0
Mean Year of Construction	1948	1961	1977	1987	1962
Mean Operating Temp (1F)	53.1	83.9	109.1	147.0	177.2
Mean Diameter (inches)	8.0	5.8	5.8	10.3	7.7
Average Spill Size (bbl)	5.2	0	1,174	0	0
Average Damage ($US 1994)	$4,467	$0	$350,000	$0	$0

4.5 Pipe Diameter Effects

CSFM-Regulated Hazardous Liquid Pipelines
For the CSFM-regulated hazardous liquid pipelines, the leak incident rate for pipe 7" in diameter and less was over three times that for pipe larger than 20" in diameter (10.35 versus 3.17 incidents per 1,000 mile years). This is especially noteworthy since the mean operating temperature for the small diameter pipe was only 77.9°F, the lowest of any diameter range. However, the age of pipe in this category and in the 8-10 inch category was fairly old, which would tend to result in higher incident rates, as shown in earlier sections. This data is also presented in Table 4-5A.

The category of pipe in the 11-15 inch diameter range also had a relatively high incident rate (8.62 incidents per 1,000 mile years). Although these lines were a good deal newer, they operated at a higher mean operating temperature.

Surprisingly, the 16-20 inch pipe diameter range had a relatively low leak rate (3.49 incidents per 1,000 mile years), despite having the highest mean operating temperature range.

The largest pipe, over 20 inches in diameter, had the lowest leak incident rate, 3.17 incidents per 1,000 mile years. However, this pipe was the newest of any category, with a mean year of pipe construction of 1984. The mean operating temperature was moderate.

Three ordinary least squares lines of best fit were prepared using this data. The first, performed using all data, indicated an overall reduction in the leak incident rate of 0.29 incidents per 1,000 mile years, per diameter inch increase, with an *R squared* of 0.76. The second, included only external corrosion leaks; it indicated a reduction of 0.26 incidents per 1,000 mile years, per diameter inch increase, with an *R squared* of 0.82. The third was performed using all leaks except external corrosion caused leaks; it resulted in a reduction of only 0.03 incidents per 1,000 mile years, per diameter inch increase, with an *R squared* of 0.31. In short, for the CSFM-regulated pipelines, there was a correlation between pipe diameter and the incident rate for external corrosion leaks, but not for leaks caused by other factors. There are several possible explanations for this correlation:

- Larger diameter pipelines represent a larger capital investment for the pipeline operator. As a result, there may be a greater proportion of the operators' resources directed toward their construction, operation, and maintenance.

- The larger diameter lines are often more important to the operators' overall operation and/or revenue generation. As a result, they may receive more attention.

! The larger lines are likely to create a greater perceived risk in the event of their rupture. This could also cause an operator to direct more resources to their protection.

Table 4-5A
Incident Rate by Pipe Diameter - CSFM Regulated Pipelines
Incidents Per 1,000 Mile Years

Cause of Incident	**0-7"**	**8-10"**	**11-15"**	**16-20"**	**20"+**
External Corrosion	6.75	4.56	5.51	1.31	.40
Internal Corrosion	.33	.27	.13	.07	.00
3rd Party/Construction	1.96	.83	.97	.36	.79
3rd Party/Farm Equipment	.33	.27	.00	.51	.00
3rd Party/Train Derailment	.00	.00	.06	.00	.00
3rd Party/External Corrosion	.22	.13	.06	.00	.00
3rd Party/Other	.00	.20	.45	.07	.00
Operating Error	.11	.10	.26	.00	.00
Design Flaw	.00	.03	.00	.00	.40
Equipment Malfunction	.44	.17	.58	.36	1.19
Maintenance	.00	.03	.06	.15	.00
Weld Failure	.00	.30	.26	.36	.40
Other	.22	.57	.26	.22	.00
Total Number of Incidents	10.35	7.46	8.62	3.49	3.17
Number of Mile Years	9,183	30,021	15,435	13,760	2,525
Mean Year of Construction	1951	1948	1962	1964	1984
Mean Operating Temp (1F)	77.9	94.11	104.81	108.44	91.17
Mean Diameter (inches)	5.6	8.7	12.6	17.6	29.4
Average Spill Size (bbl)	55	190	489	1,980	88
Average Damage ($US 1994)	$26,981	$93,735	$643,141	$194,567	$526,788

California Crude Oil Pipelines Under Study

Slightly more than 90% of California=s crude oil pipelines under study are 10" or less in nominal diameter; roughly 50% of the lines are 7" or less in diameter. Table 4-5B presents the incident rates and distribution by pipe diameter range.

A statistical analysis was performed to examine any relationship between pipe diameter and the resulting leak incident rate for these pipelines. Somewhat surprisingly, a statistical relationship was not found for this limited sample.

Two ordinary least squares lines of best fit were prepared using this data. The first, performed using all data, indicated an overall reduction in the leak incident rate of 0.50 incidents per 1,000 mile years, per diameter inch increase; however, the resulting *R squared* was only 0.26, indicating little statistical relevance. The second, analysis included only external corrosion leaks; it indicated a reduction of 0.26 incidents per 1,000 mile years, per diameter inch increase, with an *R squared* of only 0.23. In short, for the California crude oil pipelines under study, there was not a correlation between pipe diameter and the resulting leak incident rate.

Table 4-5B
Incident Rate by Pipe Diameter - Crude Oil Pipelines Under Study
Incidents Per 1,000 Mile Years

Cause of Incident	0-7"	8-10"	11-15"	16-20"	20+@
External Corrosion	1.32	8.25	.00	.00	.00
Internal Corrosion	1.32	1.65	.00	.00	.00
3rd Party/Construction	.00	.00	13.33	.00	.00
3rd Party/Farm Equipment	.00	1.65	.00	.00	.00
Total Number of Incidents	2.65	11.55	13.33	.00	.00
Number of Mile Years	756	606	75	7	44
Mean Year of Construction	1955	1947	1968	1976	1970
Mean Operating Temp (1F)	76.0	72.8	83.9	60.2	67.1
Mean Diameter (inches)	5.5	8.3	11.4	16.0	22.1
Average Spill Size (bbl)	14.0	2.7	1,174.0	.0	.0
Average Damage ($US 1994)	$7,500	$3,600	$350,000	$0	$0

4.6 Leak Detection Systems

The California crude oil pipelines under study and the CSFM-regulated hazardous liquid pipeline data were sorted into pipelines having some type of supervisory control and data acquisition (SCADA) systems, and those without. These data are presented in Tables 4-6A and 4-6B, for the CSFM-regulated pipelines and the crude oil pipelines under study respectively.

In the 1993 study, 85% of CSFM-regulated hazardous liquid pipelines had SCADA systems. For California=s crude oil pipelines under study, however, only about 9% of the pipelines had some sort of SCADA system installed.

For the crude oil pipelines under study, the leak incident rate for pipelines without these types of systems was roughly the same as the incident rate for systems with SCADA, 6.80 versus 6.13 incidents per 1,000 mile years. For the CSFM-regulated pipelines, the pipelines with SCADA had a lower incident rate than those without, 6.29 versus 11.0 incidents per 1,000 mile years. However, *this does not indicate that SCADA systems reduce leak incident rates.*

The average spill size and property damage was much larger for the crude oil pipelines under study with SCADA, than those without (1174 versus 5.2 barrels and $350,000 versus $4,467 respectively). However, there was only one leak on the 54 miles of pipeline with SCADA and nine leaks on the 441 miles of pipeline without. As a result, the data set is too small to draw any meaningful conclusions.

Although the data set was too small to be meaningful, the results are somewhat surprising. SCADA systems generally provide a means of detecting leaks quickly, minimizing spill volumes; yet the leak on the pipeline system with SCADA resulted in the largest spill volume included in the study. This situation was also noted in the 1993 study regarding CSFM-regulated hazardous liquid pipelines.

Table 4-6A

Incident Rate by Leak Detection System - CSFM Regulated Pipelines

Incidents Per 1,000 Mile Years

Cause of Incident	With SCADA		Without SCADA	
	Number	Rate	Number	Rate
External Corrosion	214	3.49	87	7.98
Internal Corrosion	13	.21	1	.09
3rd Party/Construction	53	.86	11	1.01
3rd Party/Farm Equipment	15	.24	3	.28
3rd Party/Train Derailment	2	.03	0	.00
3rd Party/External Corrosion	5	.08	2	.18
3rd Party/Other	11	.18	3	.28
Operating Error	8	.13	0	.00
Design Flaw	2	.03	0	.00
Equipment Malfunction	21	.34	6	.55
Maintenance	5	.08	0	.00
Weld Failure	14	.23	5	.46
Other	23	.37	2	.18
Total Number of Incidents	386	6.29	120	11.00
Number of Mile Years	61,351		10,904	
Mean Year of Construction	1952		1945	
Mean Operating Temp (1F)	114.3		107.0	
Mean Diameter (inches)	12.4		9.5	
Average Spill Size (bbl)	476.7		157.6	
Average Damage ($US 1994)	$228,972		$82,129	

Table 4-6B
Incident Rate by Leak Detection System - Crude Oil Pipelines Under Study
Incident per 1,000 Mile Years

Cause of Incident	With SCADA		Without SCADA	
	Number	Rate	Number	Rate
External Corrosion	0	.00	6	4.53
Internal Corrosion	0	.00	2	1.51
3rd Party/Construction	1	6.13	0	.00
3rd Party/Farm Equipment	0	.00	1	.76
Total Number of Incidents	1	6.13	9	6.80
Number of Mile Years	163		1,324	
Mean Year of Construction	1965		1951	
Mean Operating Temp (1F)	89.0		61.1	
Mean Diameter (inches)	12.4		7.0	
Average Spill Size (bbl)	1,174.0		5.2	
Average Damage ($US 1994)	$350,000		$4,467	

4.7 Cathodic Protection System

As indicated in Table 4-1A, 60% of the leaks on California's crude oil pipeline systems under study were caused by external corrosion. Because of this fact, the effectiveness of cathodic protection systems and cathodic protection system inspections were evaluated.

CSFM-Regulated Hazardous Liquid Pipelines

Nearly 100% of the CSFM-regulated hazardous liquid pipelines were protected by either impressed current or sacrificial anode cathodic protection systems. We did not find a statistically relevant difference in the effect on leak incident rates between the two types of systems. However, we found a significant difference between protected and the few unprotected pipelines. As depicted in Table 4-7A, unprotected pipelines had an external corrosion leak incident rate over five times higher than protected lines.

Although a small sample, the unprotected lines were much newer than those covered by a cathodic protection system. Unprotected lines also operated at a higher mean operating temperature and were smaller in diameter. Cathodic protection systems appear to reduce the frequency of pipeline ruptures due to external corrosion.

Data was also collected regarding the frequency of cathodic protection surveys. Table 4-7B shows the overall and external corrosion only incident rates by the average frequency of cathodic protection surveys. Ordinary least squares lines of best fit were prepared to determine whether or not the frequency of cathodic protection surveys had any statistical relevance to leak incident rates. Surprisingly, the ordinary least squares lines of best fit showed a slightly decreasing incident rate with less frequent surveys. However, there was little if any statistical relevance to this data; the *R squared* values for all incidents and external corrosion only incidents were only 0.13 and 0.01 respectively. This situation may result from operators performing more frequent surveys on pipelines with higher leak incident rates.

A multinomial logistic regression analysis was performed to analyze this parameter. It indicated that the frequency of cathodic protection surveys was not statistically correlated with the external corrosion leak incident rate.

Table 4-7A

Cathodic Protection System - CSFM Regulated Pipelines

Incident Rate Comparison per 1,000 Mile Years

Cause of Incident	Cathodically Protected		Unprotected	
	Number of Incidents	Incident Rate	Number of Incidents	Incident Rate
External Corrosion	295	4.23	9	23.12
Internal Corrosion	14	.20	0	.00
3rd Party/Construction	64	.92	1	2.57
3rd Party/Farm Equipment	18	.26	0	.00
3rd Party/Train Derailment	2	.03	0	.00
3rd Party/External Corrosion	5	.07	1	2.57
3rd Party/Other	11	.16	3	7.71
Operating Error	8	.11	0	.00
Design Flaw	2	.03	0	.00
Equipment Malfunction	27	.39	0	.00
Maintenance	5	.07	0	.00
Weld Failure	19	.27	0	.00
Other	25	.36	1	2.57
Total Number of Incidents	495	7.10	15	38.53
Number of Mile Years	69,756		389	
Mean Year of Construction	1957		1970	
Mean Operating Temperature (1F)	97		138	
Mean Diameter (inches)	12.4		8.8	
Average Spill Size (bbl)	418		39	
Average Damage ($US 1994)	$215,814		$123,100	

Table 4-7B

Average Cathodic Protection Interval During Study Period

CSFM Regulated Pipelines

Incident Rate Comparison per 1,000 Mile Years

Cause of Incident	Up to 1.0 Years		1.1-2.0 Years		2.1-5.0 Years		5.1-10.0 Years	
	Total Number	Rate	Total Number	Rate	Total Number	Rate	Total Number	Rate
External Corrosion	146	3.43	100	6.68	48	4.10	4	3.33
Internal Corrosion	10	.24	4	.27	0	.00	0	.00
3rd Party/Construction	46	1.08	9	.60	6	.51	1	.83
3rd Party/Farm Equipment	10	.24	7	.47	1	.09	0	.00
3rd Party/Train Derailment	1	.02	0	.00	1	.09	0	.00
3rd Party/Ext Corrosion	3	.07	0	.00	3	.26	1	.83
3rd Party/Other	9	.21	4	.27	1	.09	0	.00
Operating Error	6	.14	2	.13	0	.00	0	.00
Design Flaw	1	.02	1	.07	0	.00	0	.00
Equipment Malfunction	21	.49	3	.20	3	.26	0	.00
Maintenance	5	.12	0	.00	0	.00	0	.00
Weld Failure	14	.33	4	.27	1	.09	0	.00
Other	13	.31	10	.67	1	.09	0	.00
Total Number of Incidents	285	6.70	144	9.62	65	5.55	6	4.99
Number of Mile Years	42,524		14,961		11,713		1,202	
Mean Year of Construction	1954		1958		1963		1953	
Mean Operating Temperature (1F)	93.3		98.5		98.1		73.8	
Mean Diameter (inches)	11.1		16.1		11.5		8.8	

<u>California Crude Oil Pipelines Under Study</u>
64% of the crude oil pipelines included in this study are protected by cathodic protection system. 19% are unprotected. The data for the remaining 17% was either missing or unknown. This data is shown in Table 4-7C. A graphic comparison is also presented which compares the distribution of cathodically protected pipelines for both the CSFM-regulated pipelines and crude oil lines included in this study.

The leak incident rate for the crude oil pipelines under study was roughly 30% lower for cathodically protected lines than it was for unprotected lines (7.36 versus 10.80 incidents per 1,000 mile years respectively). Although the data set was small, this trend is consistent with the data presented for the CSFM-regulated hazardous liquid pipeline system.

Table 4-7D presents the incident rates for the crude oil pipelines under study which have cathodic protection systems installed. It differentiates between the leak incident rates for those systems which are regularly inspected, and those that are not. The overall incident rate for the crude oil pipelines under study with cathodic protection systems that are regularly inspected was 9.24 incidents per 1,000 mile years, 32% lower than the protected lines which did not have regular cathodic protection system inspections. The data for external corrosion leaks only yielded a greater difference; the inspected systems had an external corrosion caused incident rate of 4.62 incidents per 1,000 mile years, less than one-half the external corrosion rate for un-inspected systems.

Table 4-7C

Average Cathodic Protection Interval During Study Period

Crude Oil Pipelines Under Study

Incident Rate Comparison per 1,000 Mile Years

Cause of Incident	Cathodically Protected		Unprotected		Unknown	
	Number of Incidents	Incident Rate	Number of Incidents	Incident Rate	Number of Incidents	Incident Rate
External Corrosion	4	4.20	2	7.20	0	.00
Internal Corrosion	1	1.05	1	3.60	0	.00
3rd Party/Construction	1	1.05	0	.00	0	.00
3rd Party/Farm Equipment	1	1.05	0	.00	0	.00
Total Number of Incidents	7	7.36	3	10.80	0	.00
Number of Mile Years	952		278		258	
Mean Year of Construction	1952		1958		1947	
Mean Operating Temp (1F)	71.7		89.5		69.8	
Mean Diameter (inches)	8.2		7.3		7.3	
Average Spill Size (bbl)	173.7		1.7		.0	
Average Damage ($US 1994)	$54,314		$3,333		$0	

Table 4-7D
Incidents by Cathodic Protection Inspections - Crude Oil Pipelines Under Study
Incident Rate Comparison per 1,000 Mile Years

Cause of Incident	Inspected		Not Inspected	
	Number of Incidents	Incident Rate	Number of Incidents	Incident Rate
External Corrosion	3	4.62	3	10.17
Internal Corrosion	0	.00	2	6.78
3rd Party/Construction	1	1.54	0	.00
3rd Party/Farm Equipment	1	1.54	0	.00
Total Number of Incidents	5	7.70	5	16.95
Number of Mile Years	649		295	
Mean Year of Construction	1959		1937	
Mean Operating Temp (1F)	79.7		54.1	
Mean Diameter (inches)	8.6		7.4	
Average Spill Size (bbl)	237.4		6.8	
Average Damage ($US 1994)	$74,040		$4,000	

NOTE: Only cathodically protected pipelines have been included in the above table.

4.8 Pipe Specification Effects

Another characteristic which could influence the propensity of leak incidents is the type of steel used in construction. Tables 4-8A and 4-8B present the incident rates for varying pipe specifications for the CSFM-regulated pipelines and crude oil pipelines under study, respectively. Although different pipe specifications had varying incident rates, it must be recognized that other factors also affected these rates.

<u>CSFM-Regulated Hazardous Liquid Pipelines</u>

78% of the hazardous liquid pipelines regulated by CSFM are constructed of ASTM/API X grade material. Normally, this pipe is manufactured from relatively high quality steel, with more strictly controlled chemistry. The mean year of construction and mean operating temperature for X-grade pipe used in CSFM-regulated pipelines were 1960 and 97.6°F respectively.

22% of the pipe was constructed of ASTM A53 material. The incident rate for this material was nearly 2.7 times higher than that for X-grade material. However, this pipe was on average 10 years older, which would tend to increase the incident rate.

However, the mean operating temperature was about 12°F lower, which would tend to reduce it.

An extremely small sample of pipe fell into the *miscellaneous or other* category (less than 1%). However, the leak incident rate for this sample was very high, nearly 14 times that of X-grade pipe. Although the pipe had a mean age nearly 10 years older, it operated at a mean operating temperature roughly 30°F cooler.

Table 4-8A
Incidents by Pipe Specification - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	X-Grade		A53 and Grade B		Other	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	87	1.80	103	7.64	8	41.72
Internal Corrosion	6	.12	5	.37	0	0
3rd Party/Construction	34	.79	13	.96	2	10.43
3rd Party/Farm Equipment	10	.21	5	.37	0	0
3rd Party/Train Derailment	2	.04	0	.00	0	0
3rd Party/External Corrosion	2	.04	3	.22	0	0
3rd Party/Other	11	.23	1	.07	0	0
Operating Error	3	.06	2	.15	0	0
Design Flaw	0	.00	1	.07	0	0
Equipment Malfunction	16	.33	9	.67	0	0
Maintenance	2	.04	1	.07	0	0
Weld Failure	14	.29	4	.30	0	0
Other	13	.27	2	.15	1	5.21
Total Number of Incidents	200	4.13	149	11.05	11	57.36
Number of Mile Years	48,412		13,489		192	
Mean Year of Construction	1960		1950		1950	
Mean Operating Temp (1F)	97.6		85.3		67.1	
Mean Diameter (inches)	13.1		8.8		8.9	
Average Spill Size (bbl)	757		63		24	
Average Damage ($US 1994)	$419,728		$162,473		$49,082	

California Crude Oil Pipelines Under Study

Although the CSFM-regulated hazardous liquid pipelines were largely constructed of ASTM/API X-Grade pipe, with a small percentage of *miscellaneous or other* pipe material, the crude oil pipelines included in this study were just the opposite. 60% of the crude oil pipelines under study were constructed of *unknown* pipe specification material. 18% of the pipe was X-Grade material. The remaining 22% was either ASTM A53 or API 5L grade B pipe.

It=s interesting to note that the leak incident rate for the *unknown* pipe was by far the lowest - 1.11 incidents per 1,000 mile years, versus 7.63 and 21.74 for the ASTM/API X-Grade and ASTM A53/API 5L Grade B pipe respectively. The *miscellaneous or other* pipe was by far the oldest, with 1944 as the mean year of construction. However, this pipe was operated at the lowest mean operating temperature.

Despite the large variation in the incident rates for these different pipe groups, the reader should note that the data sample was too small to support any meaningful conclusions. Further, although external corrosion caused the largest portion of the discrepancies, this disparity is likely caused by other factors; we do not believe that external corrosion is significantly affected by pipe specification.

Table 4-8B

Incidents by Pipe Specification - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

Cause of Incident	X-Grade	A53/Grade B	Other	Unknown
External Corrosion	.00	15.53	.00	1.11
Internal Corrosion	.00	6.21	.00	.00
3rd Party/Construction	3.82	.00	.00	.00
3rd Party/Farm Machinery	3.82	.00	.00	.00
Total Number of Incidents	7.63	21.74	.00	1.11
Number of Mile Years	262	322	3	900
Mean Year of Construction	1978	1952	1955	1944
Mean Operating Temp (1F)	108.7	67.9	97.7	66.2
Mean Operating Pressure	282.0	212.9	62.8	46.3
Mean Diameter (inches)	11.0	5.9	6.5	7.0
Average Spill Size (bbl)	588.5	5.7	.0	4.0
Average Damage ($US 1994)	$176,000	$4,743	$0	$5,000

4.9 Pipe Type Effects

CSFM-Regulated Hazardous Liquid Pipelines
Table 4-9A presents the CSFM-regulated pipeline data by the type of pipe installed. The data sample was broken down into five categories: *submerged arc welded* (SAW), *seamless* (SMLS), *electric resistance welded* (ERW), *lap welded* (LW) and *miscellaneous/other*. The pipe included in this database was distributed as follows:

Pipe Type	%
Electric Resistance Welded	76.3%
Seamless	16.8%
Lap Welded	4.0%
Submerged Arc Welded	0.9%
Miscellaneous/Other	2.0%

The data indicated that lap weld pipe had a very high leak incident rate; nearly 50 incidents per 1,000 mile years. However, it was also the oldest pipe, with a mean year of construction of 1933. The weld failure caused incident rate for lap welded pipe was also the highest in the group (1.83 incidents per 1,000 mile years).

Electric resistance welded (ERW) pipe had a comparatively low incidence of leaks, 2.7 incidents per 1,000 mile years. These leaks occurred on somewhat newer pipeline systems, with a mean year of construction of 1963. They also operated at a mean temperature near the mean for the entire pipe sample.

Seamless pipe experienced an incident rate of 6.1 incidents per 1,000 mile years. However, this pipe sample had a mean year of construction of 1951. The mean operating temperature was comparatively cool, 83.6°F.

Submerged arc welded pipe had a high incidence of leaks, 10.4 incidents per 1,000 mile years. This small pipe sample had a mean year of construction of 1978. The mean operating temperature was the highest of the group, 120.3°F.

Table 4-9A
Incidents by Pipe Type - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	SMAW	SMLS	ERW	LW	Other
External Corrosion	8.35	3.66	1.47	31.59	.00
Internal Corrosion	2.09	.22	.02	1.83	.00
3rd Party/Construction	.00	.86	.45	6.41	.00
3rd Party/Farm Equipment	.00	.22	.02	1.83	.00
3rd Party/Train Derailment	.00	.00	.02	.00	.00
3rd Party/Ext Corrosion	.00	.00	.09	.00	.00
3rd Party/Other	.00	.00	.12	.46	.00
Operating Error	.00	.11	.05	1.37	.00
Design Flaw	.00	.00	.00	.46	.00
Equipment Malfunction	.00	.54	.17	1.37	.00
Maintenance	.00	.11	.00	.46	.00
Weld Failure	.00	.00	.12	1.83	.00
Other	.00	.43	.14	2.29	.00
Total Number of Incidents	10.44	6.14	2.68	49.90	.00
Number of Mile Years	479	9,280	42,112	2,184	1,106
Mean Year of Construction	1978	1951	1963	1933	1952
Mean Operating Temp (1F)	120.28	83.59	98.02	86.87	85.58
Average Spill Size (bbl)	5	83	285	87	0
Average Damage ($US 1994)	$28,008	$290,684	$602,431	$102,121	$0

California Crude Oil Pipelines Under Study

Table 4-9B presents the data for the crude oil pipelines under study. The pipe within this database was distributed as follows:

Pipe Type	Miles	%
Electric Resistance Welded	110	22.2%
Seamless	59	11.9%
Lap Welded	71	14.4%
Submerged Arc Welded	14	2.9%
Unknown	223	46.9%

The data presented in Table 4-9B illustrates the limitations of this small data sample. Specifically, the *miscellaneous/other* pipe type, which includes drilling pipe, had the highest leak incident rate, 41.67 incidents per 1,000 mile years. However, this resulted from only one incident, caused by third party damage. Because of the very small inventory of pipe within this category, a very high incident rate resulted. As stated before, this data set is simply too small to provide meaningful analysis in many instances.

The seamless pipe also had a relatively high leak incident rate (33.9 incidents per 1,000 miles years). This rate was nearly four times higher than that for the next highest pipe type (ERW, with 9.06 incidents per 1,000 mile years). The biggest factor in this difference was external corrosion, which caused 28.2 incidents per 1,000 mile years for the seamless pipe, and 6.04 incidents per 1,000 mile years for ERW.

Although this difference is large, external corrosion is not generally considered a function of pipe type. External corrosion is generally affected by pipe age, operating temperature, and other parameters. As a result, we do not believe that there is a correlation between pipe type and the leaks caused by external corrosion. This difference is likely caused by other factors and the small data sample available.

The purpose of this evaluation was twofold: first, to determine the distribution of the crude oil pipe installed and second, to identify any explainable differences in the leak incident rate caused by pipe type. While we were able to accomplish the first objective, we were unable to identify any link between pipe type and the resulting leak incident rate.

Table 4-9B

Incident Rates by Pipe Type - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

Cause of Incident	SMAW	SMLS	ERW	LW	Other*	Unknown
External Corrosion	.0	28.23	6.04	4.67	.00	.00
Internal Corrosion	.00	.00	3.02	.00	.00	1.43
3rd Party/Construction	.00	.00	.00	.00	41.67	.00
3rd Party/Farm Equipment	.00	5.64	.00	.00	.00	.00
Total Number of Incidents	.00	33.87	9.06	4.67	41.67	1.43
Number of Mile Years	43	177	331	214	24	698
Mean Year of Construction	1969	1942	1972	1929	1985	1951
Mean Operating Temp (1F)	65.0	48.5	105.2	49.0	83.7	73.9
Mean Diameter (inches)	22.0	6.4	7.0	8.3	6.3	6.9
Average Spill Size (bbl)	.0	3.3	1.7	4.0	1,174.0	25.0
Average Damage ($US 1994)	$0	$5,050	$3,333	$5,000	$350,000	$5,000

*OTHER category includes drilling pipe

4.10 Operating Pressure Effects

<u>CSFM-Regulated Hazardous Liquid Pipelines</u>
The 1993 study concluded that the relationship between normal operating pressure and the probability of pipe rupture was not statistically significant. Table 4-10A shows that there was considerable variance in the incident rate by pressure range. These differences, however, disappeared once variables such as age of pipe and operating temperature were controlled in the logistic regressions.

A simple ordinary least squares line of best fit was also determined using the overall leak data for each pressure range. The data indicated a declining leak incident rate as operating pressure increased, with an *R squared* of 0.32. However, as indicated above, the logistical regressions, which take other factors into account, did not indicate a correlation between operating pressure and leak incident rates.

An ordinary least squares line of best fit was also prepared for spill size as a function of operating pressure. The slope of the ordinary least squares line of best fit indicated a roughly 90 barrel increase in mean spill size per 100 psi increase in operating pressure. This regression resulted in an *R squared* of 0.62. It should also be noted that mean pipe diameter was also slightly higher for pipelines operating within the higher operating pressure ranges; this would also skew the results in this direction.

A similar line of best fit was prepared for average damage as a function of operating pressure. The slope of the ordinary least squares line of best fit indicated a roughly $37,000 ($US 1983), $55,035 ($US 1994) increase in average damage per 100 psi increase in operating pressure. This regression resulted in an *R squared* of 0.58. However, as noted for spill volumes, pipe diameter variances would also generally affect spill damage.

Table 4-10A
Incidents by Normal Operating Pressure - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	PSIG								
	0-100	101-200	201-300	301-400	401-500	501-600	601-800	801-1000	1001+
External Corrosion	16.67	4.11	1.63	4.12	5.16	13.05	5.83	1.26	1.58
Internal Corrosion	.45	.69	1.23	.34	.23	.20	.00	.00	.00
3rd Party/Construction	1.80	2.29	1.02	.17	.70	1.19	1.09	.60	.75
3rd Party/Farm Equip	.00	.00	.61	.00	.47	.20	.40	.06	.48
3rd Party/Train Derail	.00	.00	.00	.00	.00	.00	.00	.00	.14
3rd Party/Ext Corrosion	.00	.46	.41	.00	.00	.20	.00	.06	.00
3rd Party/Other	.00	.69	.41	.00	.00	.00	.10	.36	.14
Operating Error	.45	.00	.20	.00	.47	.00	.30	.00	.07
Design Flaw	.00	.00	.20	.00	.00	.00	.00	.06	.00
Equip Malfunction	1.80	1.37	.00	.17	.00	.00	.69	.30	.21
Maintenance	.00	.00	.00	.00	.00	.00	.20	.18	.00
Weld Failure	1.35	.00	.20	.00	.23	.00	.30	.36	.27
Other	.90	.46	.20	.00	.70	1.19	.20	.42	.14
Total Incidents	23.43	10.06	6.13	4.81	7.97	16.01	9.10	3.65	3.77
Number of Mile Years	2,219	4,374	4,895	5,818	4,264	5,058	10,112	16,732	14,597
Mean Year of Const	1933	1954	1949	1940	1946	1934	1945	1958	1949
Mean Oper Temp (1F)	130.8	92.7	82.8	86.7	121.6	125.2	159.7	116.2	104.4
Average Diameter (inches)	9.9	11.0	8.6	12.7	8.7	9.3	11.1	16.4	11.7
Average Spill Size (bbl)	17	56	5	130	149	127	456	1,292	676
Avg Damage ($1000 US ›94)	88	106	57	74	39	19	104	248	872

California Crude Oil Pipelines Under Study

Not surprisingly, most of the crude oil pipelines under study were operated at relatively low pressures. In fact, 65% of these lines were operated at 100 psig or less. The operating pressure distribution for both the CSFM-regulated hazardous liquid pipelines and crude oil pipelines under study are presented below for comparison.

Operating Pressure (psig)	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines
1 - 100	64.7%	3.3%
101 - 200	8.2%	6.4%
201 - 300	10.1%	7.2%
301 - 400	9.7%	8.5%
401 - 500	2.2%	6.3%
501 - 600	3.3%	7.4%
601 - 800	1.8%	14.9%
800+	0.0%	46.0%

As indicated in Table 4-10B, there does appear to be a relationship between operating pressure and the resulting leak incident rate. Although we believe that leak incidents caused by third party damage are not related to operating pressure, it is reasonable to assume that operating pressure and leak incidents caused by internal and external corrosion could be related. Specifically, we found that the combined internal and external corrosion leak incident rates for crude oil pipelines under study were 26.00 and 18.21 incidents per 1,000 mile years for those operated between 201 - 300 psig and 301 - 400 psig respectively. The combined external and internal corrosion leak incident rate for pipelines operated at 100 psig or less was only 4.08 incidents per 1,000 incidents per 1,000 mile years.

However, the pipe operated at higher pressures also operated at a higher mean operating temperature. But the pipe was generally newer, with a more recent mean year of pipe construction. Additionally, the lower operating pressure group of pipelines had the highest average spill size and average property damage.

Although the data set was too small to draw any conclusions at this time, we believe that this parameter should receive additional consideration after several years of additional leak data has been gathered.

Table 4-10B

Incidents by Normal Operating Pressure - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

Cause of Incident	PSIG						
	0-100	101-200	201-300	301-400	401-500	501-600	601-800
External Corrosion	2.72	.00	17.33	18.21	.00	.00	.00
Internal Corrosion	1.36	.00	8.67	.00	.00	.00	.00
3rd Party/Construction	1.36	.00	.00	.00	.00	.00	.00
3rd Party/Farm Equipment	1.36	.00	.00	.00	.00	.00	.00
Total Incidents	6.79	.00	26.00	18.21	.00	.00	.00
Number of Mile Years	736	93	115	110	25	37	22
Mean Year of Construction	1945	1970	1958	1971	1979	1970	1971
Mean Operating Temp (1F)	54.5	79.7	102.2	93.1	136.2	60.0	60.0
Average Diameter (inches)	7.3	12.8	6.5	6.9	7.6	5.6	5.0
Average Spill Size (bbl)	242.0	.0	1.7	3.5	.0	.0	.0
Avg Damage ($1000 US ›94)	$74,000	$0	$3,333	$4,100	$0	$0	$0

4.11 External Pipe Coatings

This subsection examines the incident rates for various external pipe coatings. To accomplish this, the data sample was sorted into several categories, which represented nearly all of the coatings installed on the pipelines included in this study. These coating types, their common and trade names, and the percentage of each in operation during the study period are presented below. It should be noted that the coating type was reported as *unknown* on roughly 30% of the crude oil pipeline length included in this study. The figures below show the coating type distribution of the pipelines where the coating type was reported.

Coating Type	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines	Common/Trade Names
Extruded Polyethylene with Asphalt Mastic	15.6%	6.5%	X-Tru-Coat Plexco EEC 60XT (X-Tru-Coat)
Fusion Bonded Epoxy	2.7%	1.8%	FBE Mobilox Scotchcoat 206 or 202 Thin Film Epoxy
Extruded Polyethylene with Side Extruded Butyl	3.2%	7.6%	Pritec
Extruded Asphalt Mastic	16.3%	24.9%	Somastic Asphalt Mastic
Liquid Systems	0.0%	41.6%	Coal Tar Epoxy Carboline Epoxy
Mill or Field Applied Tape	5.1%	6.0%	Polyken Tape YG III Plicoflex Raychem Hotclad Synergy
Coal Tar	6.3%	4.7%	Coal Tar or Asphalt Enamel Wrapped
Bare Pipe	25.0%	6.8%	N/A
Other Coating Types	25.8%	0.0%	N/A

As indicated, there was a far greater percentage of bare pipe in the crude oil pipeline inventory under study than the CSFM-regulated hazardous liquid pipeline inventory (25% versus 6.8%).

<u>CSFM-Regulated Hazardous Liquid Pipelines</u>

Table 4-11A presents the leak incident rates by coating type for CSFM-regulated hazardous liquid pipelines. Although pipe age and operating temperatures had the greatest effect, there did appear to be differences in performance between the coating systems. The average external corrosion incident rate for the regulated pipelines was 4.18 incidents per 1,000 mile years. Generally, the more modern coatings had external corrosion incident rates lower than average, some significantly lower. The older asphalt mastic systems had slightly higher external corrosion incident rates. The coal tar and asphalt enamel wrapped pipe had an external corrosion incident rate nearly as high as the bare pipe.

Bare (uncoated) lines, which comprised roughly 7% of the total, suffered the highest external corrosion and overall incident rates. In fact, these values were almost three times the average values for all pipelines included in the study. However, these lines had the oldest mean year of pipe construction and a mean operating temperature higher than average.

The coal tar and asphalt enamel wrapped pipelines, about 5% of the total, had an external corrosion rate nearly as high as the bare pipelines. These lines were operated at an average of 8°F above the mean operating temperature. They were also on average five years newer than the mean.

Extruded asphalt mastic coated pipe, roughly one-quarter of the total, had the third highest external corrosion and overall incident rates. This pipe had the second oldest mean year of pipe construction and the lowest mean operating temperature.

The 2% of the total pipe coated with fusion bonded epoxy had the fourth highest external corrosion and overall incident rates. The external corrosion incident rate for this coating was slightly below the overall average. This pipe was the newest sample included in the study, with a 1984 mean year of pipe construction. However, the operating temperature was the highest of the group, 115.6°F.

Extruded polyethylene with asphalt mastic, liquid systems and mill applied tape had external corrosion incident rates roughly one-half to one-third the average. The overall incident rates for these coatings were also considerably lower than the average. The mean pipe age and mean operating temperatures varied considerably among these groups. However, the pipe was generally much newer than average, with higher than average operating temperatures.

The lowest incident rates were observed on pipe with extruded polyethylene with side extruded butyl, which comprised 8% of the total. The observed external corrosion and overall incident rates for these pipelines were both less than one-tenth the average values. This pipe sample was relatively new, with a 1973 mean year of pipe construction. The mean operating temperature was moderately high, 105.8°F.

Difficulties were encountered performing multiple logic regressions using the coating type as an independent leak indicator. This occurred because the leak data and pipe data were gathered separately. Subsequently, the data were compiled using two separate databases. The coating type data was gathered for each segment of each pipeline within the State, resulting in tens of thousands of individual pipe segments. However, the leak data contained only the pipeline identification on which the leak occurred, as well as other pertinent data. The leak data did not specifically identify which segment of pipe suffered the leak. As a result, some manipulation of the data was necessary to perform the multiple logic analysis. The resulting analysis did indicate a correlation between coating type and leak incident rates.

Table 4-11A
Incidents by Coating Type - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	Coating Type (see Legend below)							
	1	2	3	4	5	6	7	8
External Corrosion	2.49	3.71	.36	5.56	1.27	1.58	11.77	11.59
Internal Corrosion	.21	.00	.00	.27	.20	.00	.20	.29
3rd Party/Construction	1.04	.00	.18	1.31	.49	.45	1.60	1.45
3rd Party/Farm Equipment	.42	2.22	.00	.22	.00	.45	.00	.87
3rd Party/Train Derailment	.21	.00	.00	.00	.03	.00	.00	.00
3rd Party/External Corrosion	.00	.00	.00	.16	.13	.00	.00	.00
3rd Party/Other	.21	.00	.00	.16	.16	.23	.80	.00
Operating Error	.21	.00	.00	.11	.07	.00	.40	.29
Design Flaw	.00	.00	.00	.05	.00	.23	.00	.00
Equipment Malfunction	.21	.74	.00	.33	.33	.00	.40	.29
Maintenance	.00	.00	.00	.11	.03	.00	.00	.00
Weld Failure	.00	.00	.00	.05	.20	.68	.40	.29
Other	.42	.74	.00	.16	.20	.45	1.80	.58
Total Incidents	5.40	7.41	.53	8.51	3.09	4.06	17.35	15.65
Number of Mile Years	4,814	1,349	5,625	18,342	30,700	4,435	5,013	3,450
Mean Year of Construction	1974	1984	1973	1956	1959	1984	1948	1962
Mean Operating Temp (1F)	107.4	115.6	105.8	80.5	98.1	104.6	103.8	105.8

Legend: Coating Types
1. Extruded PE with Asphalt Mastic
2. Fusion Bonded Epoxy (FBE)
3. Extruded PE with Side Extruded Butyl
4. Extruded Asphalt Mastic (AM)
5. Liquid Systems
6. Mill Applied Tape
7. Bare Pipe
8. Coal Tar or Asphalt Enamel Wrapped

<u>California Crude Oil Pipelines Under Study</u>
As noted earlier, 30% of California=s crude oil pipelines under study were reported as *unknown*. 18% of the pipelines were bare. Another 18% was reported to be coated with *other* types of coatings. The next two largest groupings were extruded asphalt mastic /Somastic coated lines (11%) and extruded polyethylene with asphalt mastic coated pipelines (11%). The remaining 12% of the lines were coated by a variety of coating systems.

The highest leak incident rate was encountered on the coal tar or asphalt enamel wrapped pipelines. This result is consistent with the CSFM-regulated pipeline data. The crude oil lines in this study which were coated with coal tar or asphalt enamel had a leak incident rate of 45.8 incidents per 1,000 mile years. However, this data sample was very small. The incident rate resulted from only three leaks on 22 miles of pipeline. Two of the three leaks were caused by external corrosion, resulting in an external corrosion caused incident rate of 39.5 incidents per 1,000 mile years.

Two of the other external corrosion caused leaks occurred on pipe coated with somastic and other/unknown coatings. Only one external corrosion caused leak occurred on bare pipe. The external corrosion caused incident rates for the somastic, bare, and other/unknown coated lines were 5.85, 3.82, and 7.37 incidents per 1,000 mile years respectively. These rates are similar to the overall external corrosion caused incident rate for the entire California crude oil pipeline system included in the study - 4.02 incidents per 1,000 mile years.

Table 4-11B

Incidents by Coating Type - Crude Oil Pipelines Under Study

Incidents per 1,000 Mile Years

	Coating Type (see Legend below)				
	1	2	3	4	5
External Corrosion	.00	.00	30.53	5.85	.00
Internal Corrosion	.00	.00	15.27	.00	.00
3rd Party/Construction	.00	.00	.00	.00	.00
3rd Party/Farm Equipment	.00	.00	.00	.00	.00
Total Incidents	.00	.00	45.80	5.85	.00
Number of Mile Years	164	28	66	171	34
Mean Year of Construction	1979	1978	1952	1955	1986
Mean Oper Temp (1F)	85.1	181.1	65.9	81.6	98.6

	Coating Type (see Legend below)				
	6	7	8	9	10
External Corrosion	.00	.00	3.82	7.37	.00
Internal Corrosion	.00	.00	3.82	.00	.00
3rd Party/Construction	.00	.00	.00	3.69	.00
3rd Party/Farm Equipment	31.65	.00	.00	.00	.00
Total Incidents	32	.00	7.85	11.06	.00
Number of Mile Years	156	21	262	271	440
Mean Year of Construction	60.0	1953	1940	1959	1938
Mean Oper Temp (1F)		64.4	45.0	70.9	86.1

Legend: Coating Types

1. Extruded PE with Asphalt Mastic (AM)
2. Fusion Bonded Epoxy (FBE)
3. Coal Tar or Asphalt Enamel Wrapped (CT)
4. Somastic
5. Pritec
6. Mill Applied Tape (MAT)
7. Field Applied Tape (FAT)
8. Bare Pipe
9. Other
10. Unknown

4.12 Internal Inspections

During the last several years, there have been significant advances in the technologies available to internally inspect pipelines using instrumented devices commonly called *Asmart pigs@*. These tools use several technologies to identify wall thinning, buckling, erosion, corrosion and other anomalies. These technologies, available from various vendors, differ greatly in their ability to identify and quantify various forms of pipe damage and/or deterioration. Some are precise and sophisticated, while others are much more general.

Unfortunately, most of these inspection tools are rather long. As a result, they require smooth, long radius bends to facilitate their passage. Most will not traverse short radius elbows for example.

In this section, we will attempt to:

! quantify the total length of pipelines which could be inspected using smart pigs

! identify any differences in the leak incident rates for internally inspected pipelines.

<u>CSFM-Regulated Hazardous Liquid Pipelines</u>
Out of the roughly 7,800 miles of CSFM-regulated hazardous liquid pipelines, nearly 58% (4,495 miles) are capable of being inspected using these techniques with little or no modification. 70% (3,128 miles) of the pipelines which are capable of being inspected by smart pigs, have already been inspected in this manner.

Table 4-12A presents a comparison of the incident rates for pipelines meeting three criteria:

! pipelines which have been internally inspected,

! pipelines which could be inspected with little or no modification, but had not been inspected by the end of the study period, and

! those pipelines which are not capable of being inspected utilizing a smart pig without significant modification.

The data indicates that pipe which had been internally inspected had the lowest leak incident rate. However, this pipe was also the newest of any category, with a 1963 mean year of pipe construction, 6 years newer than average. This pipe was also operated at a mean operating temperature of 121°F, 23°F higher than average and had the highest mean pipe diameter, 15.3".

We also compared the two categories of pipe which had not been internally inspected. Although the pipe which was not capable of being inspected using a smart pig was newer and operated at a lower mean operating temperature, it had an overall incident rate almost double the rate for piggable pipe which had not been inspected. However, the mean diameter for non-piggable lines was much smaller, 8.7" versus 13.0".

Table 4-12A

Incidents by Internal Inspection - CSFM-Regulated Pipelines

Incidents per 1,000 Mile Years

Cause of Incident	Internally Inspected		Not Internally Inspected		Not Piggable	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	65	2.06	39	3.47	198	6.70
Internal Corrosion	2	.06	0	.00	12	.41
3rd Party/Construction	16	.51	6	.53	42	1.42
3rd Party/Farm Equipment	8	.25	0	.00	10	.34
3rd Party/Train Derailment	1	.03	1	.09	0	.00
3rd Party/Ext Corrosion	2	.06	0	.00	5	.17
3rd Party/Other	8	.25	1	.09	5	.17
Operating Error	2	.06	2	.18	4	.14
Design Flaw	1	.03	0	.00	1	.03
Equipment Malfunction	12	.38	4	.36	11	.37
Maintenance	3	.10	0	.00	2	.07
Weld Failure	11	.35	0	.00	8	.27
Other	8	.25	8	.71	9	.30
Total Number of Incidents	139		61	5.42	307	10.39
Number of Mile Years	31,500		11,253		29,550	
Percentage of Mile Years	43.6%		15.6%		40.9%	
Total Length (miles)	3,128		1,367		3,305	
Percentage Total Length	40.1%		17.5%		42.4%	
Mean Year of Construction	1963		1941		1944	
Mean Operating Temperature (1F)	121		148		97	
Mean Diameter (inches)	15.3		13.0		8.7	

California Crude Oil Pipelines Under Study

Only 2% (roughly 8 miles) of the California crude oil pipelines under study have ever been internally inspected using a smart pig. Another 4% (approximately 20 miles) could be internally inspected, but has not been inspected in this manner. The remaining 96% (468 miles) could not be internally inspected because of physical limitations (e.g. short radius elbows). Table 4-12B presents this data, as well as the leak incident rates.

All of the leaks occurred on pipe which was not capable of passing a smart pig. This pipe was the oldest, with a 1951 mean year of pipe construction. However, it operated at the lowest mean operating temperature (72°F). Although all of the leaks occurred on this pipe, the data for the pipe which has been internally inspected was too limited to yield any meaningful results.

Table 4-12B
Incidents by Internal Inspection - Crude Oil Pipelines Under Study
Incidents per 1,000 Mile Years

Cause of Incident	Internally Inspected		Not Internally Inspected		Not Piggable	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	0	.00	0	.00	6	4.27
Internal Corrosion	0	.00	0	.00	2	1.42
3rd Party/Construction	0	.00	0	.00	1	.71
3rd Party/Farm Equipment	0	.00	0	.00	1	.71
Total Number of Incidents	0	.00	0	.00	10	7.12
Number of Mile Years	24		59		1,404	
Percentage of Mile Years	2%		4%		94%	
Total Length (miles)	8		20		468	
Percentage of Total Length	2%		4%		94%	
Mean Year of Construction	1985		1972		1951	
Mean Operating Temp (1F)	80		81		72	
Mean Diameter (inches)	6.0		18.8		7.0	

4.13 Seasonal Effects

The possibility of incident rate variations throughout the year exist for many causes. For example, heavy winter rains could result in increased external corrosion leaks during the winter. Also, heavy summer construction activity could increase third party damage during this period. In an attempt to evaluate such seasonal variations, the leak data was sorted by month of occurrence.

CSFM-Regulated Hazardous Liquid Pipelines

This data is presented in Table 4-13A for CSFM-regulated hazardous liquid pipelines. Most of the leak causes appeared to have random variations throughout the year. Also, the limited data available for most causes made it difficult to identify any trends. However, the following points were noted:

- Third party damage from farm equipment did not occur from April through August during the entire ten-year study period.

- The overall leak incident rate was lowest from April through June.

Table 4-13A

Incidents by Month of Year - CSFM-Regulated Pipelines

Incidents per 1,000 Mile Years

Cause of Incident	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
External Corrosion	3.65	3.49	4.98	3.15	3.15	3.82	5.64	3.15	3.65	3.49	5.97	6.31
Internal Corrosion	.33	.17	.17	.17	.00	.33	.33	.17	.00	.33	.33	.00
3rd Party/Construction	.50	.83	.50	1.00	.50	.50	1.66	.83	.83	1.66	1.16	.83
3rd Party/Farm Equip	.66	.33	.33	.00	.00	.00	.00	.00	.17	1.00	.33	.17
3rd Party/Train Derail	.00	.00	.00	.00	.17	.00	.00	.00	.00	.00	.00	.17
3rd Party/Ext Corrosion	.00	.00	.17	.17	.00	.17	.00	.17	.00	.17	.17	.17
3rd Party/Other	.17	.33	.83	.17	.00	.00	.17	.00	.00	.17	.00	.50
Operating Error	.00	.00	.17	.00	.00	.50	.00	.17	.00	.17	.33	.00
Design Flaw	.00	.00	.00	.00	.00	.00	.00	.17	.00	.00	.17	.00
Equipment Malfunction	.33	.83	.33	.00	.33	.17	.33	1.00	.17	.33	.17	.50
Maintenance	.00	.17	.00	.00	.00	.00	.00	.17	.17	.17	.17	.00
Weld Failure	.33	.66	.33	.33	.00	.17	.17	.33	.17	.33	.17	.17
Other	.33	.50	.17	.50	.17	.00	.50	.50	.33	.50	.50	.33
Total	6.31	7.30	7.97	5.48	4.32	5.64	8.80	6.64	5.48	8.30	9.46	9.13

California Crude Oil Pipelines Under Study
The incident rates by month of year for California=s crude oil pipelines under study are shown in Table 4-13B. Although this data set is far too limited to draw any meaningful conclusion, we noted that none of the external corrosion caused leaks occurred during the dry summer months (May through August).

Table 4-13B
Incidents by Month of Year - Crude Oil Pipelines Under Study
Incidents per 1,000 Mile Years

Cause of Incident	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec
External Corrosion	1.62	.00	.00	.81	.00	.00	.00	.00	.81	.00	1.62	.00
Internal Corrosion	.00	.81	.00	.00	.00	.00	.00	.00	.00	.00	.00	.81
3rd Party/Construction	.00	.00	.81	.00	.00	.00	.00	.00	.00	.00	.00	.00
3rd Party/Farm Equip	.00	.00	.00	.00	.00	.81	.00	.00	.00	.00	.00	.00
Total	1.62	.81	.81	.81	.00	.81	.00	.00	.81	.00	1.62	.81

4.14 Pipeline Components

Table 4-14 presents a break-down of the pipeline material, sorted by cause, for each incident which occurred on CSFM-regulated hazardous liquid pipelines. As noted, nearly 87% of all incidents occurred in the pipe body itself. Valves were responsible for another 3.1% of the incidents. 2% were caused by longitudinal weld seam failures in the pipe body. 1.6% were caused by failure at welded fittings. The remaining 6.7% were from various other causes.

100% of the incidents from California=s crude oil pipelines included in this study spilled from the pipe body.

Table 4-14

Incidents by Item Which Leaked by Cause - CSFM-Regulated Pipelines

Incidents per 1,000 Mile Years

Cause of Incident	Pipe		Valve		Pump		Weld Fitting		Long Weld	
	#	%	#	%	#	%	#	%	#	%
External Corrosion	298	67.3	0	.0	0	.0	0	.0	0	.0
Internal Corrosion	14	3.2	0	.0	0	.0	0	.0	0	.0
3rd Party/Construction	62	14.0	2	12.5	0	.0	1	12.5	0	.0
3rd Party/Farm Equip	18	4.1	0	.0	0	.0	0	.0	0	.0
3rd Party/Train Derail	2	.5	0	.0	0	.0	0	.0	0	.0
3rd Party/Ext Corrosion	7	1.6	0	.0	0	.0	0	.0	0	.0
3rd Party/Other	13	2.9	0	.0	0	.0	1	12.5	0	.0
Operating Error	5	1.1	1	6.3	0	.0	1	12.5	0	.0
Design Flaw	0	0	1	6.3	0	.0	1	12.5	0	.0
Equipment Malfunction	6	1.4	5	31.3	2	40	0	.0	1	10
Maintenance	1	.2	3	18.8	0	0	0	.0	0	.0
Weld Failure	4	.9	0	.0	0	0	4	50	8	80
Other	13	2.9	4	.25	3	60	0	.0	1	10
Total	443	100	16	100	5	100	8	100	10	100

Table 4-14 (continued)

Incidents by Item Which Leaked by Cause - CSFM-Regulated Pipelines

Incidents per 1,000 Mile Years

	Girth Weld		Thread Conn		Bolted Conn		Other	
Cause of Incident	#	%	#	%	#	%	#	%
External Corrosion	2	100	0	0	0	0	4	17.4
Internal Corrosion	0	0	0	0	0	0	0	0
3rd Party/Construction	0	0	0	0	0	0	0	0
3rd Party/Farm Equipment	0	0	0	0	0	0	0	0
3rd Party/Train Derailment	0	0	0	0	0	0	0	0
3rd Party/External Corrosion	0	0	0	0	0	0	0	0
3rd Party/Other	0	0	0	0	0	0	0	0
Operating Error	0	0	0	0	0	0	0	0
Design Flaw	0	0	0	0	0	0	0	0
Equipment Malfunction	0	0	0	0	0	0	13	56.5
Maintenance	0	0	0	0	1	25	0	0
Weld Failure	0	0	0	0	0	0	3	13
Other	0	0	0	0	3	75	2	8.7
Total	2	100	0	0	4	100	23	100

4.15 Hydrostatic Testing Interval

This section presents the leak incident rates for pipelines grouped with various hydrostatic testing intervals.

CSFM-Regulated Hazardous Liquid Pipelines

The hydrostatic testing requirements for CSFM-regulated intrastate and interstate pipelines vary significantly. Basically, the regulations for intrastate lines require periodic hydrostatic testing while those for interstate lines require only initial hydrostatic testing. Specifically, Section 51013.5 of the California Government Code requires hydrostatic testing of intrastate pipelines as follows:

- Every newly constructed pipeline, existing pipeline, or part of a pipeline system that has been relocated or replaced, and every pipeline that transports a hazardous liquid substance or highly volatile liquid substance, must be tested in accordance with 49 CFR 195, Subpart E.

- Every pipeline not provided with properly sized automatic pressure relief devices or properly designed pressure limiting devices must be hydrostatically tested annually.

- Every pipeline over 10 years of age and not provided with effective cathodic protection must be hydrostatically tested every three years, except for those on the State Fire Marshal's list of higher risk pipelines which shall be hydrostatically tested annually.

- Every pipeline over 10 years of age and provided with effective cathodic protection shall be hydrostatically tested every five years, except for those on the State Fire Marshal's list of higher risk pipelines which shall be tested every two years.

- Piping within a refined products bulk loading facility shall be tested every five years for those pipelines with effective cathodic protection and every three years for those pipelines without effective cathodic protection.

For interstate pipelines, 49 CFR 195.300 requires hydrostatic testing of newly constructed pipelines; existing steel pipeline systems that are relocated, replaced, or otherwise changed; and onshore steel interstate pipelines constructed before January 8, 1971, that transport highly volatile liquids.

The data was reviewed to evaluate hydrostatic testing effectiveness. Two separate pieces of information were gathered. First, the total number of hydrostatic tests performed on each pipeline during the ten year study period was gathered. Secondly, for each leak which occurred during the study period, the date of the preceding hydrostatic test was obtained.

To determine the average hydrostatic test interval for each pipeline during the study period, the ten year study period was divided by the total number of hydrostatic tests performed during the study period. Incident rates were then determined for each pipeline within given ranges of hydrostatic testing intervals. Table 4-15A presents the resulting data.

As indicated, the pipelines which were hydrostatically tested most frequently, up to two years average hydrostatic test interval, suffered the highest leak incident rate. However, these lines were the oldest, operated at the highest mean operating temperature, and had the smallest mean diameter. All of these factors would tend to increase the incident rate.

On the other end of the spectrum, the lines which had the longest average hydrostatic test interval suffered the lowest leak incident rates. But these lines were the newest and had the lowest mean operating temperature. Once again, these factors would tend to decrease their incident rates as we have already seen.

California's *higher risk* pipeline category would also tend to skew this data. As previously mentioned, these lines had a generally much higher leak incident rate. Those which were greater than 10 years old were required to be tested at either one or two year intervals, depending on whether or not they were cathodically protected.

Table 4-15B presents the second set of data - the time since hydrostatic testing for each leak, regardless of cause. Although not as drastic, this analysis resulted in similar results. As indicated, the pipelines which had the shortest interval between hydrostatic testing and the leak, suffered the highest leak incident rate. However, these lines were the oldest, operated at the highest mean operating temperature, and had the smallest mean diameter. All of these factors would tend to increase incident rates.

On the other hand, the lines which had the greatest length of time between hydrostatic testing and the subsequent leak, had the lowest leak incident rates. But these lines were the newest and had the lowest mean operating temperature. As has been previously noted, these factors would tend to decrease their incident rates.

With the data presented, it is difficult to readily determine the effectiveness of hydrostatic testing. The multiple regressions indicated that pipe age and operating temperatures had the greatest impact on leak incident rates. We believe that the data presented in this subsection reflected the pipe age and operating temperature effects. From these data alone, it is impossible to determine whether or not more frequent hydrostatic testing affected the frequency of leak incidents.

However, using these data, we do not conclude that more frequent hydrostatic testing reduced leak incident rates.

Table 4-15A
Average Hydrostatic Testing Interval During Study Period - CSFM-Regulated Pipelines
Incidents per 1,000 Mile Years

Cause of Incident	Up to 2.0 Years		2.1 - 5.0 Years		5.1 - 10.0 Years	
	Number	Rate	Number	Rate	Number	Rate
External Corrosion	144	9.58	113	4.67	36	2.06
Internal Corrosion	6	.40	6	.25	0	.00
3rd Party/Construction	21	1.40	15	.62	16	.92
3rd Party/Farm Equipment	0	.00	6	.25	11	.63
3rd Party/Train Derailment	0	.00	0	.00	1	.06
3rd Party/Ext Corrosion	2	.13	4	.17	0	.00
3rd Party/Other	5	.33	2	.08	0	.00
Operating Error	5	.33	3	.12	0	.00
Design Flaw	0	.00	1	.04	0	.00
Equipment Malfunction	12	.80	9	.37	4	.23
Maintenance	0	.00	3	.12	0	.00
Weld Failure	3	.20	10	.41	2	.11
Other	3	.20	12	.50	4	.23
Total Number of Incidents	201	13.37	184	7.61	74	4.24
Number of Mile Years	15,032		24,173		17,449	
Mean Year of Construction	1949		1953		1959	
Mean Operating Temp (1F)	122.3		104.6		88.5	
Mean Diameter (inches)	11.4		12.7		12.3	

Table 4-15B

Time Since Last Hydrostatic Test at Time of Leak - CSFM-Regulated Pipelines

Incidents per 1,000 Mile Years

Cause of Incident	Up to 2.0 Years		2.1 - 5.0 Years		5.1 - 10.0 Years	
	Number	Rate	Number	Rate	Number	Rate
Total Number of Incidents	147	9.83	165	6.67	109	6.46
Number of Mile Years	14,953		24,745		16,876	
Mean Year of Construction	1949		1953		1959	
Mean Operating Temp (1F)	122.3		104.6		88.5	
Mean Diameter (inches)	11.4		12.7		12.3	

California Crude Oil Pipelines Under Study

In contrast to the CSFM-regulated hazardous liquid pipelines, there are no requirements for hydrostatic testing California=s crude oil pipelines under study. As a result, it was not surprising to find that 87% of these lines had never been hydrostatically tested; 2% had been tested within the last five to ten years; 1% had been tested within the last two to five years; and 10% had been tested within the last two years. The distribution and incident rates for these crude oil pipelines is presented in Table 4-15C.

Unfortunately, there was insufficient data to allow a meaningful analysis. However, the vast majority of the lines, which had never been tested, had a leak incident rate of 5.42 incidents per 1,000 mile years. This value is less than the 6.72 incidents per 1,000 mile year incident rate for all of the pipelines included in this study. Further, the leak incident rate for external corrosion caused leaks was 3.10 incidents per 1,000 mile years, versus 4.03 incidents per 1,000 mile years for all of the crude oil pipelines under study.

The highest incident rate occurred on the pipelines which had been tested within the last two to five years. This group suffered a leak incident fate of 167 incidents per 1,000 mile years. However, this resulted from only two leaks on about four miles of pipelines.

Based on this data, hydrostatic testing does not appear to categorically result in a reduction in the leak incident rate. The reader should note that these data may be misleading. Often, operators hydrostatically test lines with a relatively high history of leaks as a preventive maintenance measure. In this way, they attempt to identify the weak points in the pipeline. When a leak develops during the hydrostatic test, water is spilled instead of oil. This prevents significant environmental damage and allows the operator to repair or replace a damaged section of pipeline and prevent crude oil spills. As a result of this practice, the leak incident rates for frequently tested pipelines would be higher, since the lines selected for testing would have a higher incidence of leaks. The results would then indicate that frequently tested pipelines had a higher leak incident rate, while in reality, the hydrostatic tests may have been a very helpful tool for preventing and/or minimizing the number of future leaks.

Table 4-15C

Hydrostatic Testing Interval During Study Period - Crude Oil Pipelines Under Study

(Incidents per 1,000 Mile Years)

Cause of Incident	Up to 2.0 Years		2.1 - 5.0 Years		5.1 - 10.0 Years		None	
	Number	Rate	Number	Rate	Number	Rate	Number	Rate
External Corrosion	0	.00	2	166.67	0	.00	4	3.10
Internal Corrosion	0	.00	0	.00	0	.00	2	1.55
3rd Party/Construction	0	.00	0	.00	1	28.57	0	.00
3rd Party/Farm Equipment	0	.00	0	.00	0	.00	1	.77
Total Number of Incidents	0	.00	2	166.67	1	28.57	7	5.42
Number of Mile Years	149		12		35		1,291	
Mean Year of Const	1966		1951		1989		1950	
Mean Operating Temp (1F)	80		68		141		62	
Mean Diameter (inches)	11.0		8.0		11.0		6.9	

4.16 Spill Size Distribution

In many instances, the spill volume is often related to the amount of environmental and/or property damage involved with an incident. While the first barrel spilled usually causes the greatest damage per barrel spilled, additional spill volume most often tends to increase the environmental and property damage to some degree.

This section presents and compares the spill volume distribution data for both CSFM-regulated hazardous liquid pipelines and the crude oil pipelines under study. As is noted, the spill volumes from the crude oil pipelines in this study are much lower than those from the CSFM-regulated pipelines.

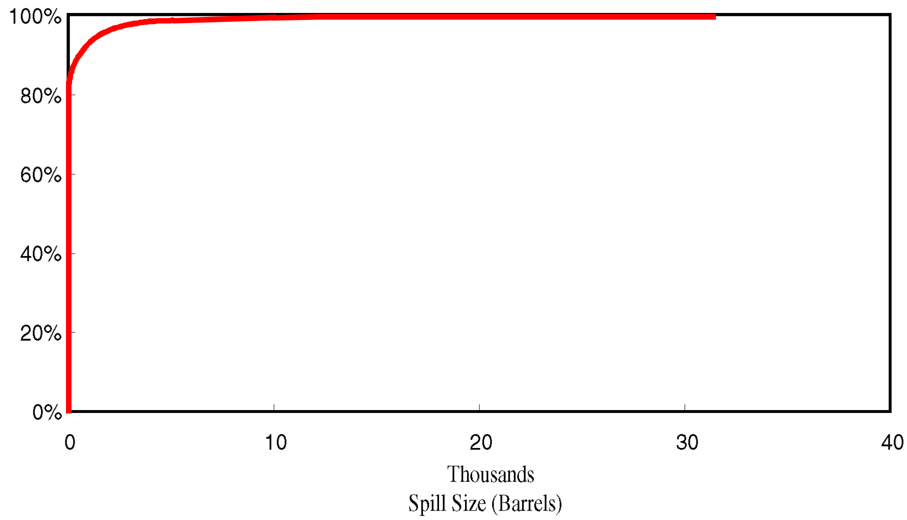
<u>CSFM-Regulated Hazardous Liquid Pipelines</u>

Selected data concerning spill size for the CSFM-regulated hazardous liquid pipeline leak sample are summarized below:

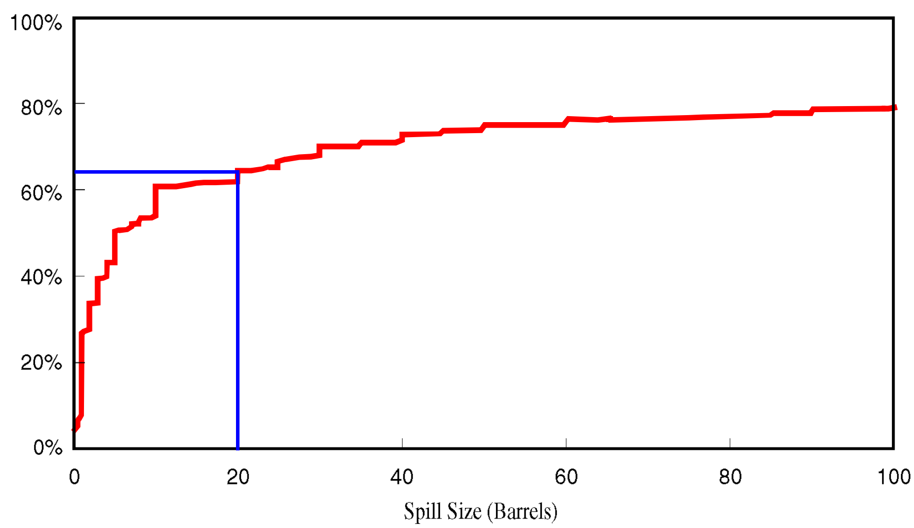
% of incidents resulted in spill volume of ≤1 bbl	27%
Median Spill Volume	5 bbl
% of incidents resulting in spill volume of ≤10 bbl	61%
% of incidents resulting in spill volume of ≤25 bbl	67%
% of incidents resulting in spill volume of ≤100 bbl	82%
% of incidents resulting in spill volume of ≤650 bbl	90%
% of incidents resulting in spill volume of ≤1750 bbl	95%
Largest spill volume	31,000

The large difference between the five barrel median spill size and the 408 barrel average spill size was caused by a relatively small number of incidents which resulted in large spill volumes. This increased the average value considerably.

Table 4-16A
Spill Size Distribution
CSFM Regulated Pipelines
Spill Size Versus Cumulative Percentage of Incidents



Spill Size Distribution
Spill Size versus Cumulative Percentage of Incidents
0 to 100 Barrels Only



NOTE: 64.48% of the incidents resulted in spills of 20 barrels or less.

Table 4-16B
Spill Size Distribution - CSFM-Regulated Pipelines

Spill Size (bbl)	Number of Incidents	%	Cumulative %
0 - .99	36	7.61	7.61
1 - 4	167	35.31	42.92
5 - 9	50	10.57	53.49
10 - 49	98	20.72	74.21
50 - 99	27	5.71	79.92
100 - 999	55	11.63	91.54
1,000 - 9,999	35	7.40	98.94
10,000 - 31,000	5	1.06	100
Total	473		

California Crude Oil Pipelines Under Study

Although the data sample is very small, the spill size distribution for California=s crude oil pipelines under study are presented in Tables 4-16A and 4-16B. This spill size distribution data is useful in establishing the likelihood, or return interval, of a given size leak from a given pipeline. By combining the leak incident rate and the spill size distribution data, the probable return interval of various sized spills can be determined. The following leak incident rates for various sized spills were established using these data.

Spill Size per 1,000 mile years	**Crude Oil Pipelines Under Study**	**CSFM-Regulated Pipelines**
Number of Incidents-any size	n/a	7.08
Incidents ≥ 1 bbl	6.72	6.54
Incidents ≥ 10 bbl	2.02	3.29
Incidents ≥ 100 bbl	1.10	1.42
Incidents ≥ 1000 bbl	0.69	0.58
Incidents ≥ 10,000 bbl	0.00	0.075

As indicated, the incident rate for various sized spills from the crude oil pipelines under study are generally less than those from the CSFM-regulated hazardous liquid pipelines. As noted above, the probable return interval from a given length of pipeline can be determined using these data. Often, this data provides a more useful result. This data is presented below for a one-mile pipeline.

	Return Interval from any 1 mile of Pipeline (Years)	
Spill Size	**Crude Oil Pipelines Under Study**	**CSFM Regulated Pipelines**
Any size	n/a	141
≥ 1 bbl	149	153
≥ 10 bbl	495	304
≥ 100 bbl	909	704
≥ 1,000 bbl	1,450	1,720
≥ 10,000 bbl	infinite	13,300

This data can also be analyzed to determine the probable recurrence interval for various sized spills from all of the 7,800 miles of CSFM-regulated hazardous liquid pipelines and 496 miles of crude oil pipelines under study.

	Crude Oil Pipelines Under Study		CSFM Regulated Pipelines	
	Return Interval from 496 miles of pipeline		Return Interval from 7,800 miles of pipelines	
Spill Size	Time	Leaks per year	Time	Leaks per year
Any size	n/a		6.6 days	55
≥1 bbl	3.6 months	3.3	7.2 days	51
≥10 bbl	1.0 years		14 days	26
≥100 bbl	1.8 years		1.1 months	11
≥1,000 bbl	2.9 years		2.7 months	4.5
≥10,000 bbl	infinite		1.7 years	

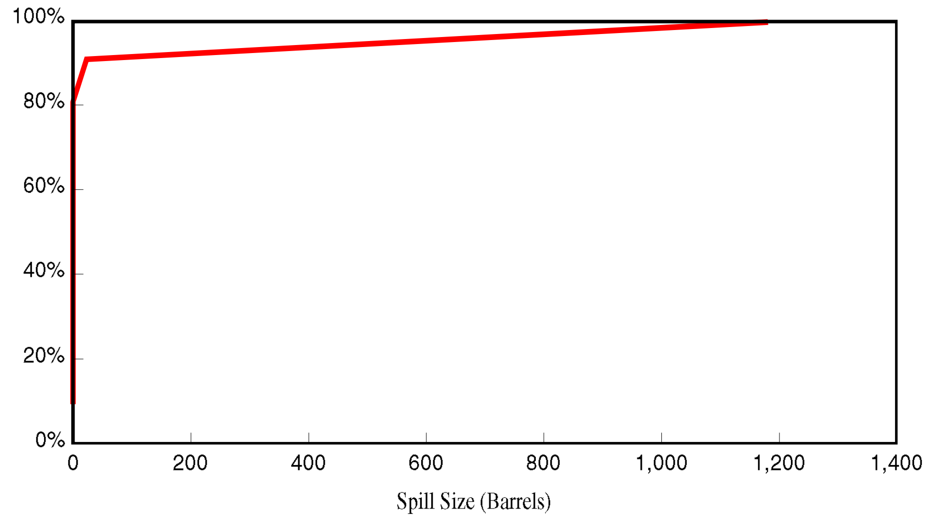
As indicated, because of the relatively small length of crude oil pipelines under study and the lower frequency of a given size spill, the return interval for a given sized spill from these crude oil pipelines is far greater than for the CSFM-regulated hazardous liquid pipelines.

Table 4-16C

Spill Size Distribution

Crude Oil Pipelines Under Study

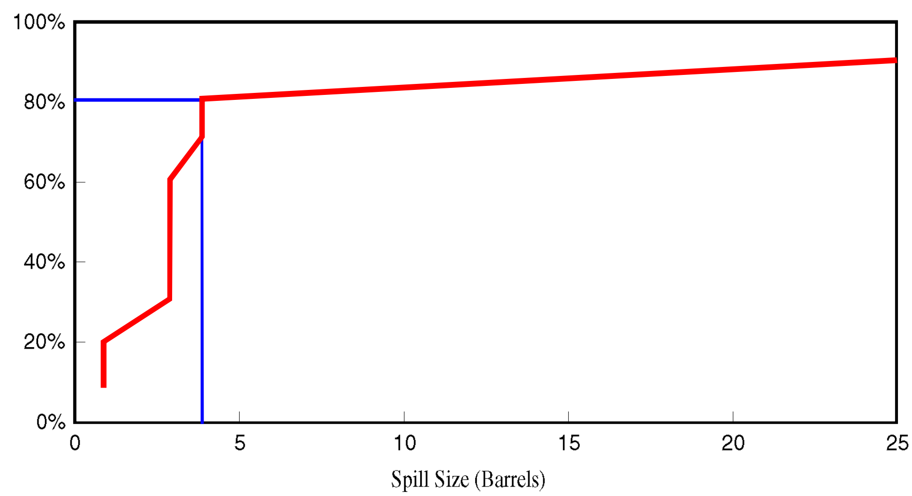
Spill Size Versus Cumulative Percentage of Incidents



Spill Size Distribution

Spill Size Versus Cumulative Percentage of Incidents

0 to 100 Barrels Only



NOTE: 80.00% of the incidents resulted in spills of four barrels or less.

4.17 Damage Distribution

The property damage distribution was very similar to the spill size distribution discussed in the preceding section. A few incidents resulted in relatively large property damage values which increased the mean values considerably. To the greatest extent possible, the damage figures used in this study included all costs associated with the incident (e.g. value of spilled fluid, clean-up, injury, judgements, fatalities, etc.).

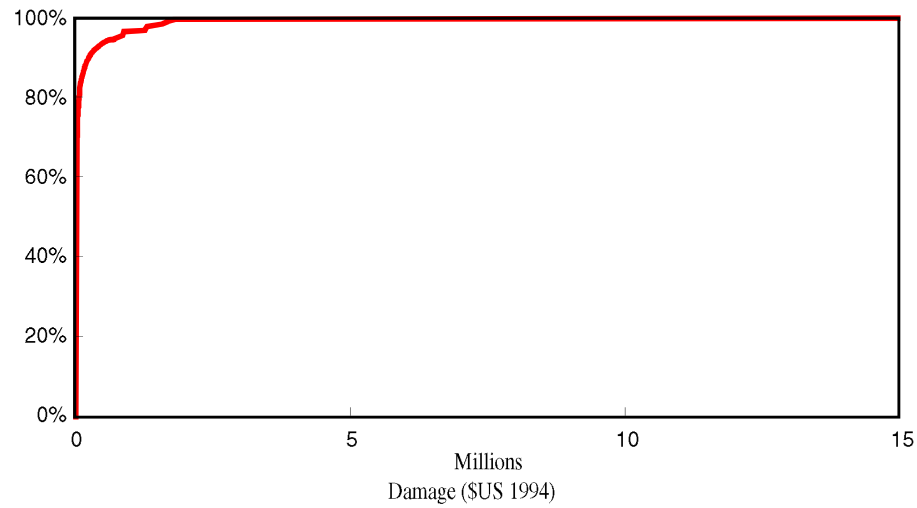
CSFM-Regulated Hazardous Liquid Pipelines

Table 4-17A depicts the property damage distribution data for CSFM-regulated hazardous liquid pipelines. All data has been shown in constant 1994 U.S. dollars. The values for each year were converted to 1994 constant dollars using the U.S. City Average Consumer Price Indices as published by the U.S. Bureau of Labor Statistics. A few points along the curve are presented below:

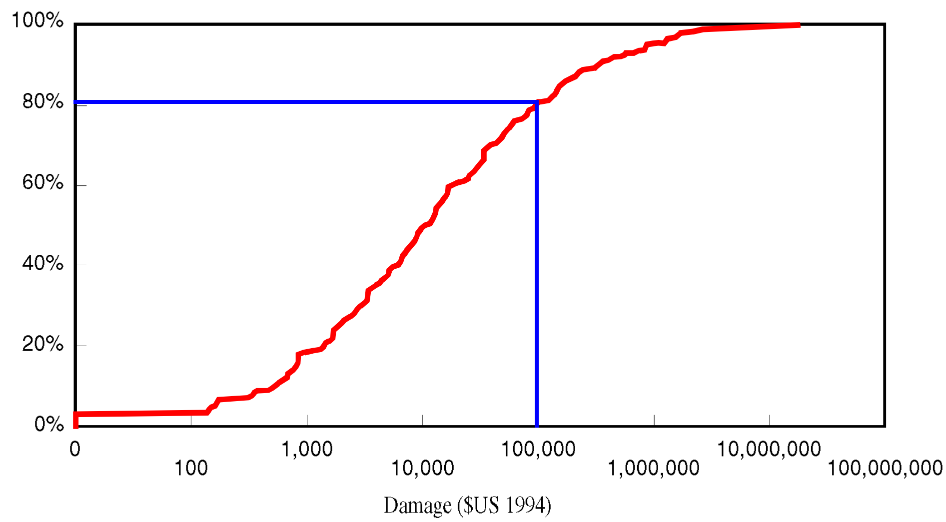
% of incidents resulting in damages of $2,000 of less	25%
Median damage	$11,000
% of incidents resulting in damage of $57,000 or less	75%
% of incidents resulting in damage of $270,000 or less	90%
% of incidents resulting in damage of $880,000 or less	95%
Largest reported damage for a single incident	$17,500,000*

*Figure may be increased as additional claims are settled.

Table 4-17
Property Damage Distribution
CSFM Regulated Pipelines



Damage Distribution
Logarithmic Scale



NOTE: 80.72% of the incidents resulted in damage of $100,000 or less.

California Crude Oil Pipelines Under Study

Although this data sample is very small, the damage distribution data for California=s crude oil pipelines under study are presented in Tables 4-17B. In comparing Tables 4-17A and 4-17B, the shape of the curves are nearly identical for the CSFM-regulated hazardous liquid and crude oil pipelines in this study, except for the incidents which caused extensive property damage. Although the occurrence of spills which resulted in modest amounts of property damage were essentially the same for both groups of pipelines, the frequency of spills which caused $10,000 ($US 1994) in property damage or more was much greater for the CSFM-regulated pipelines.

These data are useful in establishing the likelihood, or return interval, of a leak resulting in a specific amount of damage from a given pipeline. By combining the leak incident rate and the damage distribution data, the probable return interval of various spills for a given pipeline can be determined. The following leak incident rates were established using these data.

Damage Resulting From Spill ($US 1994)	Incidents per 1,000 mile years	
	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines
$100	6.72	6.85
$1,000	6.72	5.80
$10,000	1.34	3.64
$100,000	1.14	1.36
$1,000,000	0.00	0.28
$10,000,000	0.00	0.028

As noted in the previous section, the probable return interval from a given length of pipeline can be determined using these data. Often, this provides a more useful result. These data are presented below for a one-mile pipeline.

Damage Resulting From Spill ($US 1994)	Return Interval from any 1 Mile of Pipeline (Years)	
	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines
$100	149	146
$1,000	149	172
$10,000	746	275
$100,000	1,090	735
$1,000,000	infinite	3,570
$10,000,000	infinite	35,700

These data can also be analyzed to determine the probable recurrence interval for various sized spills from all of the 7,800 miles of CSFM-regulated hazardous liquid pipelines and 496 miles of crude oil pipelines under study.

Spill Size ($US 1994)	Crude Oil Pipelines Under Study	CSFM-Regulated Pipelines
	Return Interval from 496 miles of these Pipelines	Return Interval from 7,800 miles of these Pipelines
$100	3.6 months, or 3.3 leaks per year	1 week, or 53 leaks per year
$1,000	3.6 months, or 3.3 leaks per year	7.8 days, or 45 leaks per year
$10,000	1.5 years	12 days, or 28 leaks per year
$100,000	2.2 years	1.1 months, or 11 leaks per year
$1,000,000	infinite	5.5 months, or 2.2 leaks per year
$10,000,000	infinite	4.6 years

As indicated, because of the relatively small length of crude oil pipelines in this study and the lower frequency of spills resulting in relatively large values of damage, the return interval for spills from these pipelines resulting in significant damage is greater than for the CSFM-regulated hazardous liquid pipelines.

4.18 Incident Rates by Internal Coating or Lining

The possibility for significant internal corrosion was envisioned on the crude oil pipelines evaluated in this study. As a result, data regarding the installation of internal liners or coatings was gathered. However, only about 1% of the pipelines had an internal liner or coating installed. Although not statistically relevant, all of the leaks occurred on unlined or uncoated pipe. The data sample was too small to facilitate an analysis of this parameter.

Table 4-18
Incident Rates by Above vs. Below Grade - Crude Oil Pipelines Under Study
(Incidents per 1,000 Mile Years)

Cause of Incident	Above	Below	Both
External Corrosion	.00	4.19	.00
Internal Corrosion	.00	1.40	.00
3rd Party/Construction	.00	.7	.00
3rd Party/Farm Equipment	.00	.7	.00
Total Number of Incidents	.00	6.98	.00
Total Number of Mile Years	45	1,432	10
Mean Year of Construction	1978	1952	1947
Mean Operating Temp (1F)	86.7	74.3	60
Mean Diameter (inches)	3.2	7.7	5.5
Average Spill (bbl)	0	122.1	0
Average Damage ($US 1994)	$0	$39,020	$0

4.19 Incident Rates by Above versus Below Grade Pipe

96.3% of the 496 miles of crude oil pipelines under study was buried below grade. Of the remaining pipe, 3% (15 miles) was installed above grade, and 0.7% (3 miles) was installed with a combination of both buried and above grade segments.

Table 4-19 presents the incident rates for the above and below grade pipelines. As indicated, all of the leaks occurred on the buried sections of line. However, this should not be considered statistically relevant because of the very limited data sample.

Cause of Incident	Above	Below	Both
External Corrosion	.00	4.19	.00
Internal Corrosion	.00	1.40	.00
3rd Party/Construction	.00	.70	.00
3rd Party/Farm Equipment	.00	.70	.00
Total number of Incidents	.00	6.98	.00
Number of Mile Years	45	1432	10
Mean Year of Construction	1978	1952	1947
Mean Operating Temperature (1F)	86.7	74.3	60
Mean Diameter (inches)	3.2	7.7	5.5
Average Spill (bbl)	0	122.1	0
Average Damage ($US 1994)	$0	$39,020	$0

4.20 Recovery of Spilled Volumes

Although only 10 leaks occurred during the three-year crude oil pipeline study period, the relationship between the volumes spilled and the volume recovered was reviewed. As indicated in Table 4-20, of the 1,221 barrels of crude oil spilled, roughly two-thirds (800 barrels) were recovered.

The lowest recovery percentage occurred from the external corrosion leaks. This relationship is not surprising, since these leaks are typically very slow, low leak rate incidents.

Table 4-20
Recovery of Spilled Volumes - Unregulated California Crude Oil Pipelines

Cause of Incident	Spilled (bbl)	Recovered (bbl)	Recovered (%)
External Corrosion	18	8	42%
Internal Corrosion	26	25	96%
3rd Party/Construction	1,174	764	65%
3rd Party/Farm Equipment	3	3	100%
Total	1,221	800	65%

4.21 Injuries and Fatalities

CSFM-Regulated Hazardous Liquid Pipelines
49 injuries and 3 fatalities resulted from incidents on CSFM-regulated hazardous liquid pipeline system during the ten year study period. Nearly 94% of the injuries and 100% of the fatalities resulted from only three incidents; it is remarkable that just over one-half percent of the total incidents resulted in all of the fatalities and nearly all of the injuries during the entire ten year study period. These incidents are briefly described below:

May 25, 1989, San Bernardino
On May 12, 1989, a freight train derailed in San Bernardino, California. On May 25, 1989, 13 days later, a CSFM-regulated interstate petroleum products pipeline ruptured. The National Transportation Safety Board determined that during the derailment, and later during the movement of heavy equipment to remove the wreckage, the high-pressure products pipeline adjacent to the tracks was damaged and weakened. Less than two weeks after the wreck, the pipeline ruptured and spilled more than 300,000 gallons of gasoline into a nearby neighborhood. Some of the gasoline ignited and caused significant fire damage. This incident resulted in two fatalities and thirty-one injuries.

February 22, 1986, Placer County
During the removal of an abandoned section of pipeline which had been relocated around a collapsed railroad trestle, approximately one barrel of gasoline was spilled. The fuel was ignited by a torch being used by the railroad's welding crew. As a result of the ignition, three welders jumped from the bridge into the creek below. This incident resulted in one fatality and one injury.

November 22, 1986, Tustin
A ten-inch API 5L X52, ERW pipe longitudinal weld seam ruptured. This resulted in the spill of about 11,000 barrels of unleaded gasoline. Fortunately, the spill did not result in fire or an explosion. Documents filed with the USDOT indicated that there were no injuries or fatalities meeting federal reporting criteria. (See also Chapter 3 of this study.) However, 14 emergency responders from the local fire department were treated for symptoms consistent with hydrocarbon exposure: eight were treated at a medical facility, four were treated and released at the scene, and one was hospitalized for observation. In addition, one civilian was also treated at the scene and released. These were treated as 14 injuries for the purposes of this study.

Each of these incidents had a different cause. Two were caused by some form of third party damage, while the third was caused by a material defect.

The number of incidents resulting in injuries and fatalities was too small to draw any meaningful conclusions. However, it should be noted that all injuries and fatalities occurred on pipelines carrying refined petroleum products. Crude oil pipeline incidents did not result in any injuries or fatalities during the study period.

The current requirements are basically the same for product and crude pipelines. However, although a limited sample, this data indicated that the risks to human life were likely greater for refined product pipelines. On the other hand, both crude and refined product pipeline incidents resulted in similar environmental concerns.

As mentioned previously, *all* injuries, regardless of severity, were included in these data. For instance, the 1986 Tustin incident resulted in 14 injuries which did not meet the USDOT injury reporting criteria. Deleting these injuries alone would have reduced the resulting injury rate for this study by more than one-third. The reader should keep this factor in mind while reading this section. Otherwise, the public injury risk could be over-exaggerated. Sufficient data was not available to sort the injuries incurred during the study period by severity.

California Crude Oil Pipelines Under Study

No injuries or fatalities occurred on the California crude oil pipelines during the three year study period. Further, the data sample was too small to be meaningful.

For example, if one simply applied the fatality rate or 0.042 fatalities per 1,000 mile years, which resulted from the CSFM-regulated hazardous liquid pipelines, one would anticipate a fatality every 16 years for the 496 miles of crude oil pipelines included in this study. This recurrence interval is greater than the three-year study period. As a result, one would not expect a fatality during this study. Further, as discussed above, the risk to human life from crude oil spills is likely less than for refined petroleum product pipelines, which would tend to increase the recurrence interval.